High Temperatures & Electricity Demand

An Assessment of Supply Adequacy in California

Trends & Outlook

A Report of the California Energy Commission Staff
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Executive Summary

During the summer of 1998, the California Independent System Operator issued several calls for voluntary reductions in electricity usage. On four occasions, the Independent System Operator issued Stage II alerts which signaled that operating reserves had fallen below 5 percent.[1] Under a Stage II alert, the Independent System Operator requests that the utility distribution companies curtail their interruptible load customers so that the Independent System Operator can maintain an operating reserve of at least 5 percent.

At the time of these alerts, temperature levels and electricity demand across the western half of the country were also at record high levels. The coincidence of high temperatures and electricity demand over most of the western half of the country strained the electricity supply and transmission system to its limits. These events brought into question the overall adequacy of the electricity supply system within the region overseen by the Western Systems Coordinating Council.

- Was the summer of 1998 a truly unique event in terms of the history of recorded temperatures and electricity demands or was it an indication that electricity supplies have not kept pace with demand growth?

- How likely is it that we will experience a similar shortage this summer?

- Aside from demand uncertainty due to extreme weather conditions, what other factors will affect the system's ability to reliably meet load?

These are the questions that Commission staff addresses in this report.

High Temperatures and Electricity Demand

An examination of historical temperature data for the western states in the Western Systems Coordinating Council from the last 40 years revealed the following:

- Only one other year in the last 40, 1985, had as many days where temperatures were as hot as those that occurred last summer.

- The 3-day moving average high temperature for the Western Systems Coordinating Council on the weekdays when the Independent System Operator declared a Stage II alert was over 95°F. In the past forty years, the average high temperature for the entire Western Systems Coordinating Council exceeded 95°F on only 31 weekdays. The probability that four would occur in a single year is 1-in-50.

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[1] For control areas within its boundaries, such as the California ISO, the Western Systems Coordinating Council requires a seven percent minimum operating reserve. Areas that have a high percentage of hydroelectric generation, such as the Northwest, have a lower minimum operating reserve requirement. The minimum operating reserve requirement ensures the reliability the electricity system in case of sudden loss of generation or transmission capacity, sudden increases in load. It also provides local are protection in case of a system separation.

- When hot temperatures prevailed across California, in 1998, two of the three regions of the Western Systems Coordinating Council, the Pacific Northwest and the Desert Southwest,[2] also experience high temperatures. There is also a strong correlation between the timing of peak demand in the California and the peak demand for the entire Western Systems Coordinating Council.

The staff used historical temperature and demand data for 67 utility service areas within the Western Systems Coordinating Council to derive two high temperature forecasts of electricity demand in the Western Systems Coordinating Council for the summer of 1999. One forecast assumed temperature conditions corresponding to a 1-in-40 year probability, (i.e., similar to the temperature conditions that occurred in the 1998). The other forecast assumed temperature conditions corresponding to a 1-in-5 year probability. These two hot weather demand forecasts along with a forecast of demand for the Western Systems Coordinating Council under average, or expected temperature conditions, then became inputs to a computer model that staff would use to evaluate summer peak demand supply adequacy.

The staff found that small changes in average temperatures across the area under control of the California Independent System Operator had a large impact on peak demand. The average high temperature of the Independent System Operator control area in the 1-in-40 year scenario was five-degrees hotter than the average high temperature under expected temperature conditions. Peak demand in the 1-in-40 scenario, however, increased by approximately 4,000 MWs, which was 8.5 percent higher than the expected peak.

Peak Demand Supply Adequacy

The staff analysis of supply adequacy focused on one week in August, which contained the coincident California and Western Systems Coordinating Council peak demand for our two hot weather demand scenarios and average weather demand scenario. The hourly demand data corresponding to these three scenarios for the entire Western Systems Coordinating Council were put into the Multisym™ model, which emulates both the generation and transmission of electricity throughout the entire Western Systems Coordinating Council. The model provided the following results:

- In all three scenarios, the demand for electricity was met. There were no unserved loads. However, during the hour of the California coincident peak demand, the amount of electricity capacity in excess of peak demand varied significantly among the four Western Systems Coordinating Council reliability regions for each scenario.

- The margin of available capacity over peak demand for the California-Mexico region under expected 1-in-5 and 1-in-40 year temperature conditions was 7, 4, and 0 percent respectively. These numbers were the same for the California Independent System Operator control area. In California, nearly all the available interruptible load was called on to meet peak demand under the 1-in-40 year temperature scenario.

[2] The four reporting regions of the WSCC are the Northwest Power Pool Area, the Rocky Mountain Power Area, the Desert Southwest Area, and the California-Mexico Power Area.

- For the Desert Southwest region of the Western Systems Coordinating Council, the margin of available electricity capacity over demand for the three scenarios was 5, 5 and 2 percent. The Desert Southwest region is a net exporter of electricity to California. However, the flows of electricity on the northern portion the West of the River system of transmission lines that connect Southern California to the Southwest are well below their rated carrying capacity. Without the addition of significant amounts of new generation capacity in the Desert Southwest region of the Western Systems Coordinating Council, less generation will be available from this region to provide reserve support to California during the summer peak demand season.

- The Northwest and Rocky Mountain region have more than adequate electricity capacity over peak demand, but this excess capacity is misleading in terms of these regions' ability to provide reserve support to other regions in the Western Systems Coordinating Council. Hydroelectric capacity comprises a significant portion of the installed capacity in these regions. The capacity is, therefore, energy-limited in that it depends on how much water is behind the dam to make that capacity available.

- The two factors in the staff's modeling that are the source of significant uncertainty with respect to the ability to reliably meet demand are hydro availability and generation outages. In the three demand scenarios, the model shows 2,752 MW of generation in the California Independent System Operator control area being forced out at the time of the California peak demand. This number is significantly higher than the 1,500 MW assumed by the California Independent System Operator in its ***1999 Summer Operations Plan.***

- The staff's modeling assumed average year hydro conditions. While hydro conditions in the summer of 1998 were above average, they could just as easily have been below average.

Based on the modeling results and forecasts of expected load growth in California, the staff concludes the following:

- In the absence of significant amounts of new generation capacity being added in the Southwest, less generation will be available from this region for export to California in the coming years. The State will, therefore, become increasingly more dependent upon imports from the Northwest to meet summer peak loads.

- The availability of surplus hydro energy from the Northwest will become more critical to California being able to reliably meet peak demand in the summer until new merchant plants come on line in California.

- The combination of deregulation of the generation market throughout the rest of the Western Systems Coordinating Council and low reserve margins will result in increased regional competition for available generation in the Western Systems Coordinating Council. Therefore, historical levels of imports into California from both the Southwest and Northwest cannot be relied upon to be available in the future.

- Continued load growth in California in future years means higher peak demands. The staff's forecast of peak demands for the summer of 1999 under low probability temperature scenarios become forecasts of peak demand under high probability temperature scenarios in future years. By 2002, the expected peak demand for the California Independent System

Operator control area will be equal to the peak demand in the staff's 1-in-5 year scenario. By 2004, the expected California Independent System Operator peak demand will equal the peak demand in the 1-in-40 year scenario. Without additional generation being added in those years, the probability of frequent Stage II alerts during the summer peak demand period becomes greater.

Supply Adequacy Trends and Outlook

The North American Electric Reliability Council in their ***1999 Summer Assessment*** report came to the same conclusion reached by the Commission staff in their assessment of supply adequacy in the California-Mexico and the Desert Southwest region of the Western Systems Coordinating Council. The North American Electric Reliability Council found that capacity shortfalls in these regions would be likely under two conditions: 1) extreme temperatures during the summer peak demand season and 2) above average number of forced outages of generators. The North American Electric Reliability Council also noted that demand growth in the west was outpacing new generation additions.

Warnings about tight western electricity supplies, especially during super hot weather conditions, have also come from ICF Kaiser, a consulting firm. They speculate that price spikes would be more likely to occur in the summer of 2000 because hydro availability for the summer of 1999 is greater than normal.

The overall trend in peak demand capacity reserves for the California and Desert Southwest regions of the Western Systems Coordinating Council has been downward for the last ten years. The ten-year average margin of available capacity over firm peak demand for the California region is a little less than 14 percent. In 1997, the actual peak capacity margin for the California region was 7.8 percent.

Firm peak demand does not include the loads of interruptible customers. In 1997, the actual peak capacity margin for the California region after serving interruptible load customers was 3.7 percent. When capacity reserves were high, interruptible load customers had a very low probability of being asked to curtail demand. Without significant amounts of new generation capacity being built in California, reserve margin levels will remain low, increasing the likelihood that interruptible load customers will be asked to curtail consumption during the summer peak demand season. Interruptible load customers that choose not to curtail consumption will adversely impact system reliability.

The Western Systems Coordinating Council’s annual forecast of capacity reserve margins at the time of peak demand for the four sub-regions has consistently been higher than the actual margin. The factor contributing most to actual capacity reserves being significantly lower than forecasted reserves has been that the forecast did not include an estimate of the amount of capacity unavailable due to forced outages and unplanned maintenance.

Age is a significant factor in a power plant’s reliability. As they age, power plants require more maintenance and are more prone to forced outages. In California, almost half of the installed generation capacity in the State is comprised of oil and natural gas-fired combustion turbines, steam turbines, combined cycle and cogeneration units. Of that total, 61 percent (15,818 MW) is thirty years older or older.

In the California sub-region of the Western Systems Coordinating Council, the average amount of generation capacity that was unavailable at the time of the peak demand because of maintenance or forced outages for the ten-year period 1988-1997 was 5,821 MW. The staff's scenario modeling of supply adequacy under the three temperature related demand scenarios was conservative compared to this historical average in that it showed only 3,373 MW of capacity in the California-Mexico region being unavailable at the time of the peak demand.

Most of the older generation capacity in California consists of units which have reliability-must-run contracts with the California Independent Systems Operator. The owners of facilities with reliability-must-run contracts are expected to maintain these units consistent with a standard of "Good Industry Practice." Improved maintenance on California reliability-must-run units to increase their availability will contribute to greater reliability during the summer peak demand season, but it will not be enough to offset declining reserve margins.

Even with improved maintenance, the availability of fossil units in California and the rest of the Western Systems Coordinating Council over the next three years is uncertain, as they will have to be out of service for some period of time to install required emission control devices for oxides of nitrogen. The timing of any oxides of nitrogen retrofit activity could result in one, or more, large thermal units being unavailable during the summer peak demand season; therefore, keeping track of this activity will have important consequences for system reliability.

Based on information provided by its members, the Western Systems Coordinating Council's outlook for net generation additions over the next five years will not keep pace with forecasted demand growth. The California Energy Commission staff forecast of new generation additions is more optimistic in that it includes many of the merchant plants that have filed applications for siting approval from the Energy Commission. The majority of these units will not come on line until 2002 and 2003.

There is a high degree of uncertainty surrounding the on-line dates for many of the new merchant plants in California. The timing of these new additions depends not only on how quickly they proceed through the Commission's siting process, but also on the market signals coming out of the California Power Exchange and the California Independent System Operator.

As was noted earlier, the combination of deregulation and thin reserve margins throughout the Western Systems Coordinating Council will mean a highly competitive market for new generation regardless of where it is located. The evidence of this competition can already be seen. Several transmission projects are in various stages of construction and planning that would increase the import capability into the regions of the Western Systems Coordinating Council experiencing the most rapid growth in demand: Southern Nevada and Mexico. These projects do not contribute to new capacity, but they do signal a redirection of historical flows of electricity over the bulk transmission network in the Western Systems Coordinating Council.

The risks and costs of supply disruptions are the burden of consumers in this new competitive electricity market. The North American Electric Reliability Council has stated that future generation investment will only occur in response to proper marketplace signals, and that to ensure continuing resource adequacy, the risk of failing to serve the customer must be recognized and incorporated into the price structure.

Incorporating the risk of failing to serve customers into the price structure will not ensure reliable service if customers have no way of indicating what they are willing to pay for reliability. This brings into question whether customers must always be served and if regulators, or the Independent System Operator, have a responsibility of ensuring a minimum level or reliability for all customer loads. Whoever has that responsibility will have to make periodic assessments of supply adequacy for the entire Western Systems Coordinating Council region to determine the amount of generation capacity available to meet load and provide a check on the performance of the market and its success at attracting new capacity.

Introduction

Prolonged periods of hot weather present the biggest challenge to the reliability of an electricity network. Electricity demand is high during these periods. Power plants that typically cycle up and down to meet fluctuations in daily load will operate flat-out at their highest output level. Minor maintenance on these plants may end up being delayed, and with them operating at continuously high output levels, the probability of forced outages on these plants increases. Transmission lines also become more susceptible to outages during hot weather because of thermal overloading.

For California, the summer of 1998 was one where temperatures often reached the 100°F plus range. The demand for electricity in California also reached record levels prompting calls from the California Independent System Operator (ISO) for voluntary cutbacks in electricity consumption. On four occasions, the ISO's calls for voluntary cutbacks were followed-up with calls to the utility distribution companies to curtail their interruptible load customers. This signaled that the ISO's operating reserves, the amount of capacity above demand to cover fluctuations in demand and other contingencies, had fallen below five percent. Surplus generation from other western states was limited as high temperatures prevailed throughout the west, driving the demand for electricity across the western half of the country to new levels. This coincidence of high temperatures and demand over such a large geographic region strained the electricity supply and transmission system in the west to its limits.

Were the temperature conditions and electricity demands of the summer of 1998 unique or an indication that electricity supplies in the west have not kept pace with demand growth? The Energy Commission staff addresses this question in the three sections of this report.

The first section of this report begins with the Energy Commission staff's investigation into the relationship between peak electricity demand and temperatures across the Western Systems Coordinating Council (WSCC) reliability region. The section puts 1998's summer's temperatures into an historical perspective using historical average high temperature and hourly electricity demand data covering the WSCC for the last 40 years. The rest of this section describes the staff's use of this historical data to develop hourly load data for the entire WSCC corresponding to two hot weather scenarios for the summer of 1999. The hourly loads for these two scenarios became input into a computer model that the staff then used to evaluate supply adequacy in the WSCC. (This analysis of supply adequacy is described in the next section of the report.)

Section II of the report addressees the question: has the electricity supply system in the west kept pace with demand growth? The staff answers this question by putting the hourly loads for the two hot weather scenarios described in Section I into a model that simulates the generation and transmission of electricity throughout the WSCC region. The modeling focuses on the week that contains the coincident peak demand for California. The model reports available reserves after meeting load and flows on the major transmission interties that connect the states within the WSCC region as well as the transmission paths within California that define the ISO pricing zones. The results from these simulations provide a more accurate understanding of the reserve shortages that occurred in 1998 and the probability of such shortages occurring in the future.

The final section of this report examines the trend over the last ten years of generation reserves in the WSCC and identifies factors that staff believes will influence the ability of the electricity supply system in the WSCC to meet future summer peak demands.

Section I: High Temperatures and Electricity Demand

This section provides a technical assessment of the relationship between weather and peak electricity demand. It starts with a description of how historical temperature data are treated in our analysis of electricity demand. A comparison of 1998 summer temperatures in California and the rest of the western U.S. to temperatures in previous summers follows this description. The section then proceeds with a description of a series of analytical steps leading to two demand scenarios for California and the other western states in the Western Systems Coordinating Council (WSCC) reliability region. Each scenario corresponds to an historical pattern of hot weather that has an assigned probability of occurring. These two hot temperature-related demand scenarios will then be used in assessing supply adequacy in California and the rest of the WSCC.

Background

During the first summer of California's restructured electricity market, California's Independent System Operator (ISO)'s issued four Stage II alerts. A Stage II alert indicates that the ISO would not be able to maintain a 5 percent operating reserve unless interruptible load customers are curtailed. At the time of these alerts, temperature levels and electricity demand across the western half of the country were also at record high levels. The coincidence of high temperatures and electricity demand over most of the western half of the country strained the electricity supply and transmission system to its limits. The record high levels of electricity demand during the summer of 1998 raised concern regarding the relationship between temperature and electricity demand. Were the weather conditions that prevailed during the summer of 1998 unusual or were forecasts of summer peak demands based on an unrealistic assessment of expected summer temperature conditions?

The answer to this question has significant implications to both the affordability and availability of electricity. Electricity consumers benefit from reliable peak demand forecasts because these forecasts signal the need for new investment in generation and transmission, and thereby reduce the risk that the electricity system will either be overbuilt, or underbuilt, too costly, or too unreliable.

Linking Temperature Data to Electricity Demand

When temperatures rise throughout the WSCC, the corresponding increase in demand for electricity in sparsely populated areas will not be as great as in densely populated areas. The relevance of this relationship is important when trying to forecast increases in electricity demand in California and the rest of the WSCC in response to increases in temperature. To capture the responsiveness of electricity demand to temperature, the staff assigned temperatures to the various load regions of the WSCC. We acquired daily minimum and maximum temperatures at 42 different weather sites across the WSCC for the years 1959-1998 from the National Oceanic and Atmospheric Administration. Temperature data from each weather station outside of California were assigned to utilities; each utility was then assigned to one of 17 transmission area[3]; the transmission areas in turn were assigned to one of the four WSCC sub-regions. In California, the temperature data was first assigned to a climate zone, the climate zones were then assigned to a utility, and then the utilities were assigned to a transmission area. The mapping of utilities to weather stations, and of utility service regions to transmission area and WSCC sub-regions, is provided at the end of this section.

The average high temperature for the transmission areas outside of California were calculated for each day of the year by multiplying the daily high temperature assigned to each utility by the ratio of the utility's load to the total load of the transmission area that the utility is in.[4] [5] Daily high temperatures for the climates zones within the Pacific Gas and Electric, Southern California Edison, the Los Angeles Department of Water and Power service areas were weighted by the number of air-conditioners within each climate zone.[6] [7] The adjusted temperatures for each utility were then summed to arrive at the average high temperature for the transmission area. Average high temperatures for the four sub-regions of the WSCC were calculated by multiplying each transmission area's average high temperature by the ratio of the transmission area's load to the load of the sub-region and then summing the results. This process was repeated to derive average high temperatures for the WSCC (multiplying the sub-region's temperature by the ratio of sub-region's load to total WSCC load.)

Temperature and Peak Demand Trends in California

Peak electricity demand does not always happen on the hottest day of the year. The Energy Commission staff and others involved in electricity demand analysis and forecasting have found a strong correlation between peak electricity demand and a buildup of high temperatures over several days. To quantify this buildup of temperatures over consecutive days, the staff calculated each day's highest temperature as a 3-day moving average. Weights were assigned to each of the three days prior to averaging with the current day's maximum temperature being given the highest weight.[8]

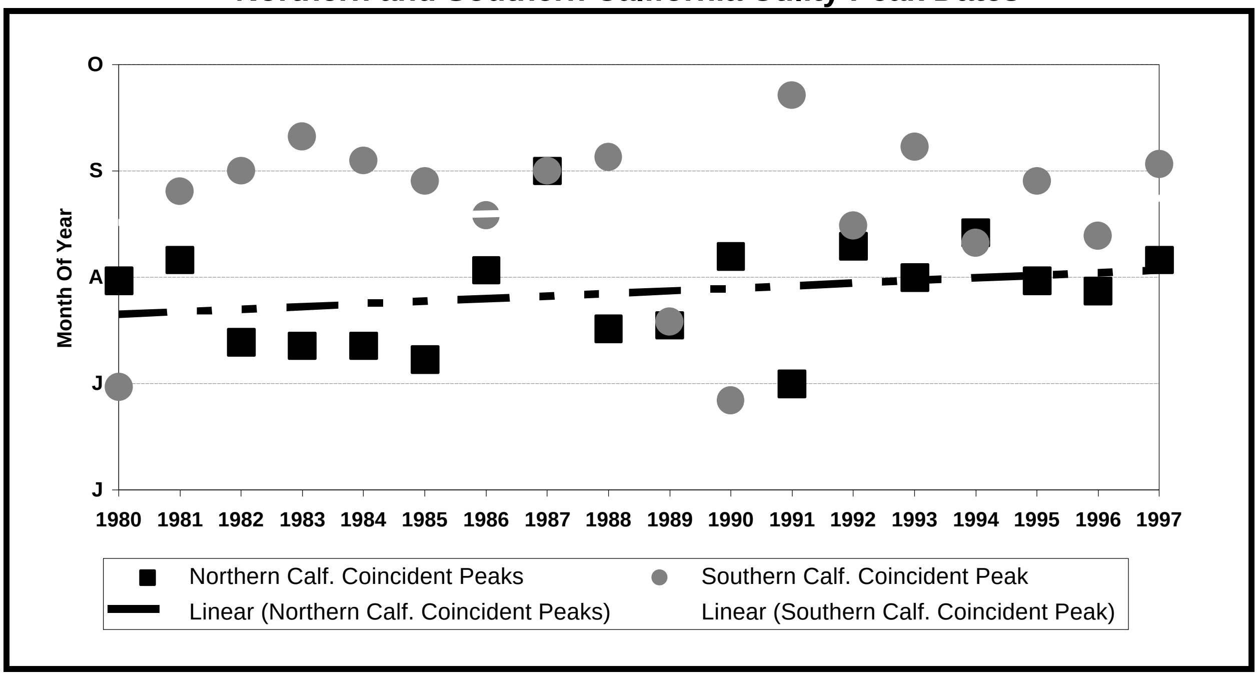
Peak electricity demand also does not always occur in the hottest period. For example in 1998, July 28th had the highest 3-day moving average temperature for the year, but several factors served to moderate demand. Curtailed load from the previous day's Stage II Alert stayed offline and July 28th was slightly cooler than the day before. There was also some reduction in demand from customers on hourly-interval meters who cut back consumption in response to high prices.

[3] The transmission areas were geographic regions defined in the model used by the staff for determining supply adequacy; they also included the various transmission congestion zones as defined by the California ISO.
[4] If a transmission area was made up of four utilities and the daily load for each utility represented exactly one fourth of the daily load for the transmission area, then the corresponding temperature for that utility would be multiplied by 0.25 to derive the load-weighted temperature.
[5] The load data for each utility was a daily average for the years 1993-1997. Data came from the utilities FERC Form 714 filings.
[6] Ideally, the best way to weight summer high temperatures is to use factors that correspond directly to air-conditioning load. Such factors include residential loads and commercial loads, which are more responsive to temperature, or the number of air conditioning appliances. Unfortunately, the staff did not have these data for areas outside of California.
[7] San Diego Gas & Electric service area is contained within one climate zone; therefore, no weighting of temperatures assigned to SDG&E was required.
[8] Staff used weights of 0.1, 0.3, and 0.6.

Fortunately, for the ISO, temperature patterns across Northern and Southern California are not uniform. Northern California's peak demand is more likely to occur in late July or early August, whereas Southern California usually peaks a month later (see **Figure I-1**). The weather diversity, and consequently the load diversity between Northern and Southern California, somewhat lessens the demands on the ISO's system. The timing of the coincident peak demand for the entire State occurs when we would expect the system to be most strained, more so than the occurrence of the non-coincident peak for the two parts of the state.

Figure I-1 shows a plot of the non-coincident peak dates for the two dominant Northern California utilities—Pacific Gas and Electric Company (PG&E) and Sacramento Municipal Utility District (SMUD) and the three largest Southern California utilities—Southern California Edison Company (SCE), Los Angeles Department of Water and Power (LADWP) and San Diego Gas and Electric Company (SDG&E). The addition of the two linear trend lines illustrates the natural load diversity of the Northern and Southern California regions. The Northern California trend runs from mid July to the first week of August. The Southern California trend line runs from mid to late August.

FIGURE I-1
Northern and Southern California Utility Peak Dates



Source: Energy Commission staff.

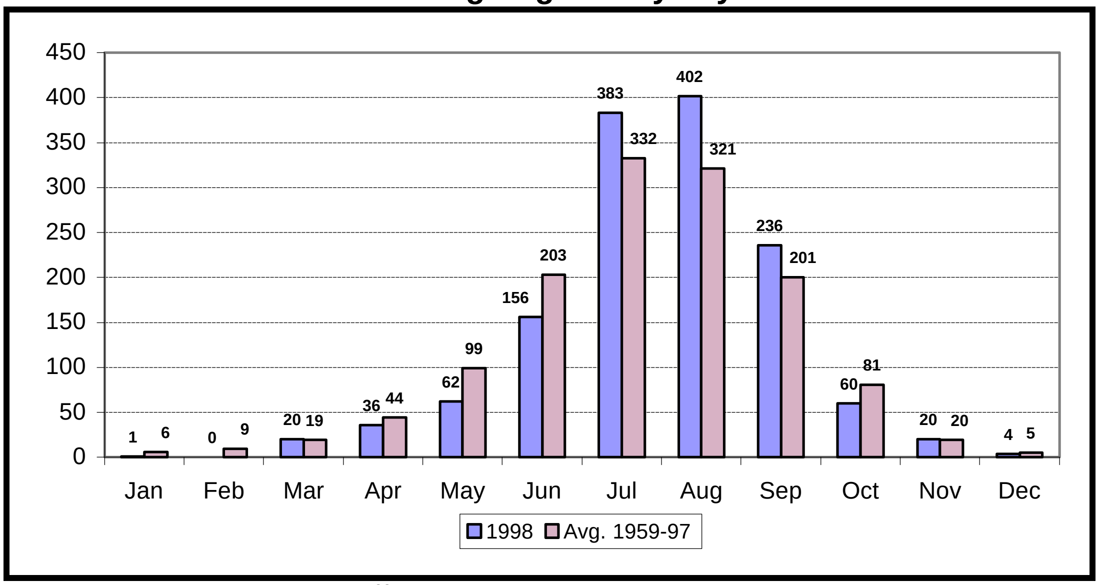
The Summer of 1998

Figure I-2 illustrates one of the reasons average high temperatures across the WSCC in the summer of 1998 were unusual compared to the temperatures seen in an average summer. **Figure I-2** compares the monthly distribution of cooling-degree days (CDD)[9] in 1998, averaged across the WSSC region, to those that occur in an average summer. Cooling degree-days is a unit of measure that indicates when temperatures are high enough to cause air conditioning load. In

[9] CDD = ((daily high temperature + daily low temperature) ÷ 2)-65, if > 0 the value is rounded up to the nearest integer, if < 0 the value is 0.

1998, there was only a 3 percent increase in the number of cooling degree-days compared to the 40-year average (1,380 CDD v. 1,340 CDD). However, the occurrence of cooling degree-days in 1998 was more concentrated. July and August had 56 percent of the cooling degree-days compared to an average summer in which these months normally have 49 percent, whereas June had 23 percent fewer cooling degree-days compared to an average summer.

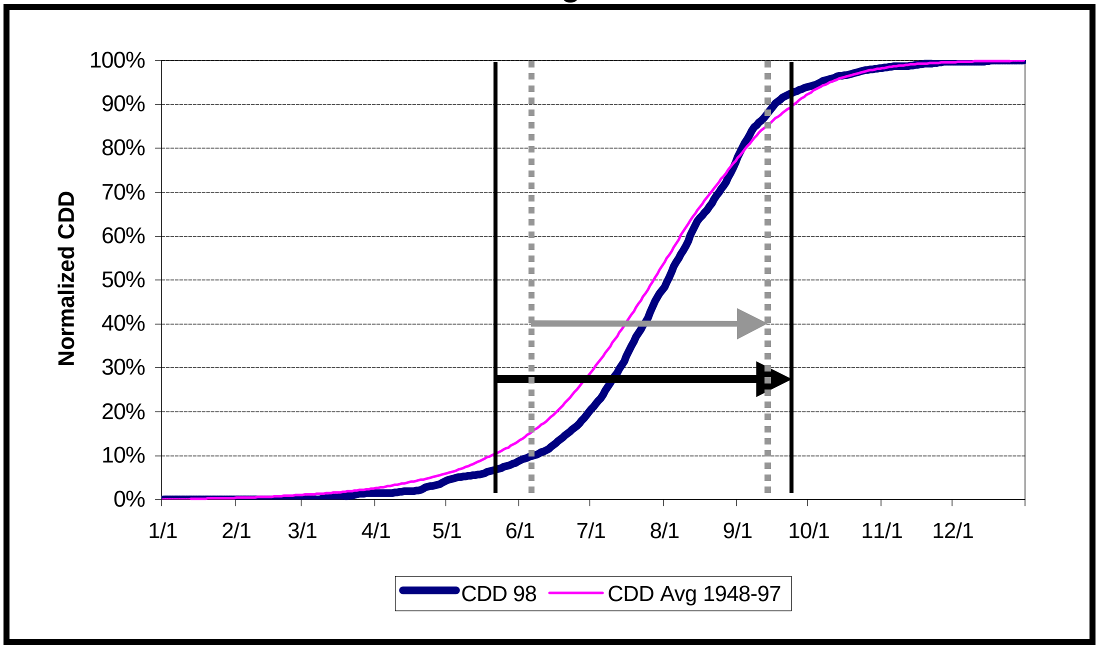
FIGURE I-2
WSCC Cooling Degree Days by Month



Source: Energy Commission staff.

Figure I-3 also confirms that the occurrence of hot weather in 1998 was concentrated into a shorter period. Figure I-3 shows the boundaries of the 1998 summer cooling load period. The summer cooling load period is defined as the period of time that captures the middle 80 percent of the cumulative cooling degree-days. **Figure I-3** shows that the average cooling load period typically occurs between the last week in May through the last week in September. The cooling load period for 1998, however, started in approximately the second week of June and lasted only through first week of September.

FIGURE I-3
WSCC'S Cooling Load Period

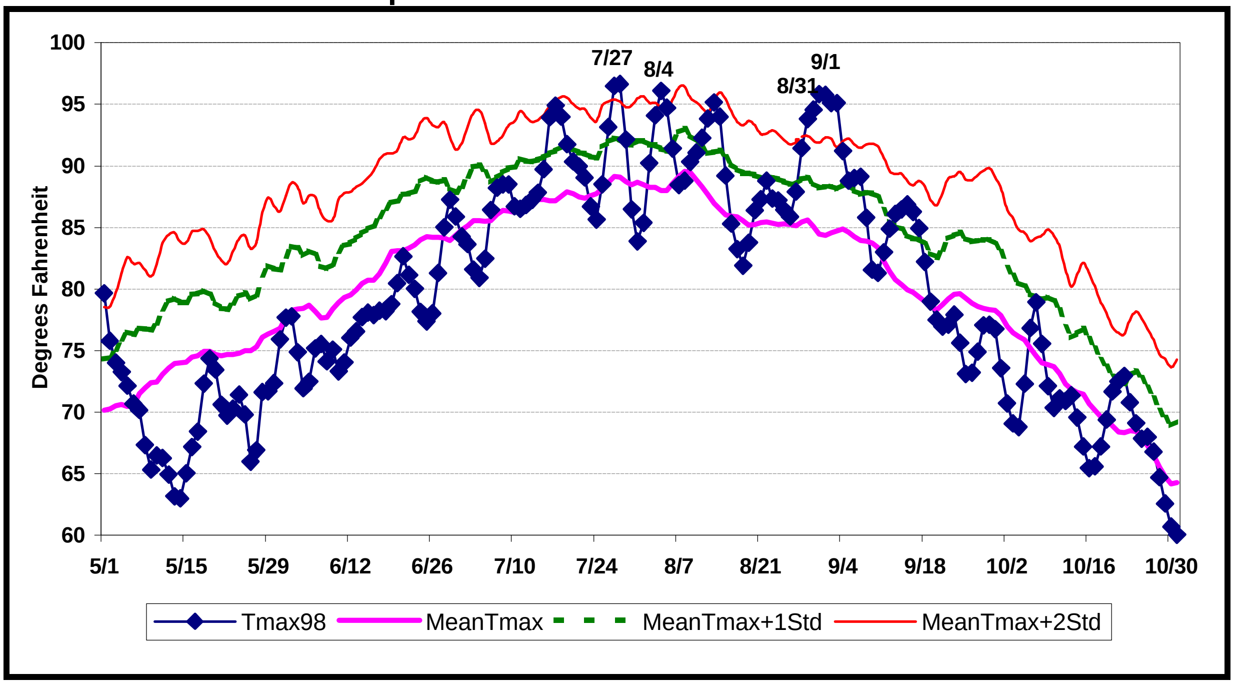


Source: Energy Commission staff.

Figure I-4 shows the mean value of the 1959-97 3-day moving average of daily high temperatures (**MeanTmax**) for the months of May through September for the WSCC, the one and two standard deviation boundaries (**MeanTmax+1Std, MeanTmax+2Std**), and an overlay of the 3-day moving average high temperatures for the same months in1998 (**Tmax98**). On the four weekdays that the California ISO called Stage II alerts, the 3-day moving average high temperature for the WSCC exceeded 95 degrees. In the past forty years, there were only 31 weekdays when the average high temperature for the WSCC exceeded 95 degrees. The likelihood that four of those days would fall in a single year is only 1-in-50.

The 3-day moving average high temperatures for the WSCC on the days of the Stage II alerts were also unusual in that each exceeded the mean value high temperature by more than two standard deviations. This may be a useful indicator for predicting future Stage II alerts. In total, the summer of 1998 had ten days where the 3-day moving average high temperature for the WSCC exceeded the 40-year mean for that day by two standard deviations. Only one other year in the last 40, 1985, had as many hot days.

FIGURE I-4
1998 Average Daily WSCC High Temperatures
Compared to the 1959-1997 Mean Value

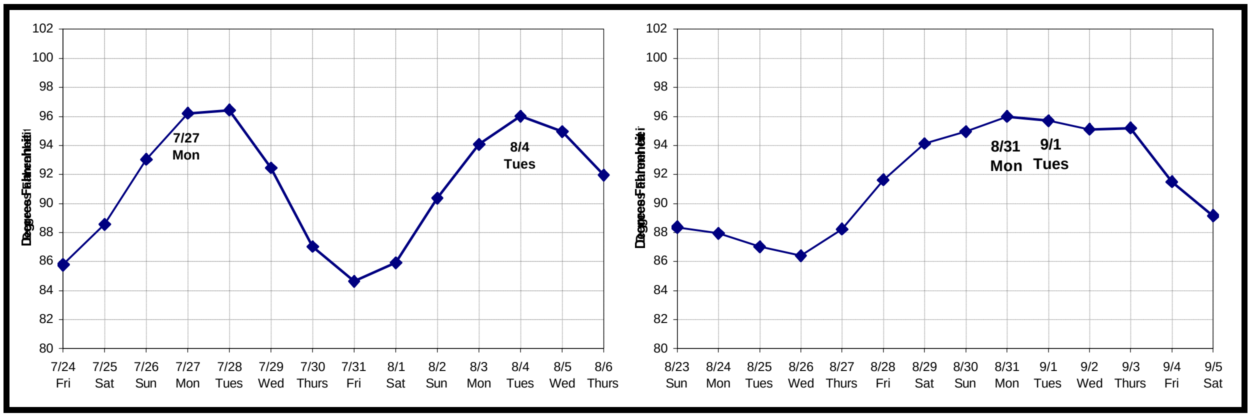


Source: Energy Commission staff.

The hot periods during 1998 were also significantly hotter than average. Looking at the single hottest 'heat storm' period, on July 28, 1998, the 3-day moving average high temperature of 96.4 degrees for the WSCC region was the fourth highest over the last forty years; and the 3-day moving average high temperature for California of 101.9 degrees, the third highest. The WSCC's all-time average high temperature was 98.5 degree on July 9, 1985. **Table I-1** provides a ranking of California's high temperature using temperature data going back to 1959.

On the days California ISO declared Stage II alerts— July 27, August 4, August 31, and September 1— the rest of the WSCC was also experiencing high temperature and load conditions. **Figure I-5** displays the average high temperatures across the entire WSCC during the summer of 1998 along with the dates of the Stage II alerts. The figure reveals that there is a strong relationship between the 3-day moving average high temperature across the WSCC and the timing of the Stage II alerts. **Table I-2** provides the 3-day moving average temperatures for the transmission areas and the WSCC on the days of, and surrounding, the four Stage II alerts.

FIGURE I-5
WSCC 3-Day Moving Average High Temperatures



Source: Energy Commission staff.

Table I-1
California's Highest Annual 3-Day Moving Average Temperatures

Rank	Date	Day Of the Week	Degrees Fahrenheit
40	09/03/91	Tue	92.9
39	08/20/64	Thu	93.3
38	08/19/60	Wed	94.2
37	08/15/63	Thu	94.8
36	08/14/89	Mon	94.9
35	08/15/62	Wed	95.1
34	08/30/68	Wed	95.2
33	08/03/75	Sun	95.8
32	08/09/65	Mon	96.4
31	07/25/59	Sat	96.5
30	08/08/90	Wed	96.9
29	07/31/79	Tue	97.0
28	08/16/66	Tue	97.1
27	07/26/73	Thu	97.2
26	08/19/86	Tue	97.6
25	09/05/61	Tue	97.7
24	08/09/71	Mon	97.9
23	07/25/74	Thu	98.0
22	08/09/70	Sun	98.0
21	08/25/85	Sun	98.2
20	07/28/95	Wed	99.2
19	09/07/77	Wed	99.6
18	08/06/78	Sun	99.6
17	09/02/87	Wed	99.7
16	09/02/82	Thu	100.0
15	07/28/72	Wed	100.1
14	08/22/69	Wed	100.2
13	08/13/96	Tue	100.2
12	08/01/93	Sun	100.2
11	07/29/80	Tue	100.6
10	08/13/94	Sat	100.7
9	08/30/76	Mon	100.9
8	08/17/92	Mon	101.1
7	08/30/67	Wed	101.1
6	08/06/97	Wed	101.2
5	09/05/84	Wed	101.4
4	08/07/83	Sun	101.5
3	08/04/98	Tue	101.9
2	08/28/81	Wed	102.2
1	09/04/88	Sun	103.4

Source: Energy Commission staff.

TABLE I-2
3-Day Moving Average Temperatures for the 17 Transmission Areas and the WSCC On Days Of and Day Surrounding the Four Stage II Alerts

Date	Day Of Week	Alberta	Arizona	BCHA	CFE	CNORTH	CSCE	CSDGE	CSF	Colorado	ID-SPP	IID	LADWP	New Mexico	North-West	So. Nevada	Utah	Wyoming	WSCC Avg.
07/24/98	Fri	95.0	95.9	78.8	103.8	85.6	86.6	82.7	72.9	76.9	93.9	102.8	81.9	90.1	81.3	91.4	83.7	75.8	85.8
07/25/98	Sat	98.0	101.5	81.7	107.6	90.0	88.8	83.8	72.5	77.8	94.5	107.1	82.8	90.8	84.0	98.3	81.7	79.5	88.6
07/26/98	Sun	102.0	106.4	88.4	111.9	92.3	94.3	85.7	70.3	79.0	96.4	114.7	88.1	90.8	90.8	103.7	85.8	80.4	93.0
07/27/98	**Mon**	**104.2**	**109.2**	**93.7**	**116.0**	**93.1**	**98.0**	**89.0**	**69.3**	**79.9**	**97.8**	**117.5**	**95.0**	**90.6**	**95.8**	**106.3**	**88.2**	**82.8**	**96.2**
07/28/98	Tue	103.7	108.3	96.5	116.4	89.8	99.2	90.4	67.8	80.8	98.3	118.7	96.1	91.8	97.0	106.9	86.0	85.5	96.4
07/29/98	Wed	102.6	103.7	91.4	111.4	83.9	94.7	87.2	67.8	81.2	97.7	115.3	92.8	95.1	89.9	108.2	88.1	82.2	92.5
07/30/98	Thu	96.1	103.5	80.3	110.0	78.7	88.7	84.8	68.5	78.7	93.3	113.0	86.2	97.4	80.3	107.0	90.6	73.2	87.0
07/31/98	Fri	88.2	102.8	74.8	108.0	81.9	87.3	84.5	72.5	74.7	87.9	110.3	84.6	94.0	75.0	102.7	92.4	73.4	84.6
08/01/98	Sat	84.8	103.0	73.2	106.1	90.2	90.6	85.4	76.8	76.2	85.6	108.7	86.4	91.6	74.6	101.2	86.9	77.7	85.9
08/02/98	Sun	90.6	104.5	79.7	107.6	97.1	95.1	85.8	82.2	79.4	89.1	110.5	90.0	94.1	80.9	103.3	84.0	80.0	90.4
08/03/98	Mon	97.5	108.6	84.4	112.8	102.4	98.8	86.5	88.0	76.8	93.0	114.6	93.5	93.2	85.8	105.8	86.0	74.3	94.1
08/04/98	**Tue**	**104.0**	**110.1**	**86.0**	**115.3**	**105.4**	**100.8**	**86.8**	**88.0**	**73.3**	**97.8**	**117.7**	**96.6**	**88.6**	**88.0**	**107.4**	**88.1**	**70.1**	**96.0**
08/05/98	Wed	107.0	107.5	82.9	114.2	105.1	99.1	86.3	80.2	72.6	101.7	119.4	95.8	84.0	85.3	108.5	90.7	73.4	94.9
08/06/98	Thu	98.3	105.2	79.4	109.7	99.0	95.7	85.4	72.0	77.0	101.3	113.9	91.9	85.8	81.4	108.9	94.1	79.1	92.0
08/23/98	Sun	78.9	107.7	71.2	111.3	89.3	99.1	90.3	73.0	88.2	86.6	112.7	95.8	92.2	72.4	108.3	94.8	89.3	88.4
08/24/98	Mon	79.1	103.0	72.3	110.5	91.8	96.4	87.0	72.5	91.1	86.2	111.7	94.6	92.5	73.6	106.5	89.1	88.9	88.0
08/25/98	Tue	83.7	100.0	74.6	107.7	89.0	93.2	87.8	67.9	84.1	88.4	111.2	90.5	92.7	76.3	101.8	87.9	84.4	87.0
08/26/98	Wed	84.0	100.9	74.0	107.0	87.4	92.5	87.9	68.7	82.7	87.6	109.8	88.6	91.0	76.2	101.4	86.5	85.3	86.4
08/27/98	Thu	88.2	105.2	75.9	106.3	90.9	91.8	88.0	71.3	83.9	89.8	109.8	89.3	92.9	78.6	102.3	85.6	83.9	88.2
08/28/98	Fri	96.8	109.6	80.8	111.5	92.6	95.5	89.1	69.7	81.0	94.5	113.5	91.6	89.6	83.4	105.9	86.9	85.3	91.6
08/29/98	Sat	99.1	108.6	83.5	112.9	94.3	101.1	94.5	69.1	82.2	97.5	116.6	96.3	89.7	85.4	106.3	90.1	87.5	94.1
08/30/98	Sun	97.5	107.2	83.6	113.2	94.6	104.6	97.7	65.9	85.1	93.9	116.0	100.9	90.6	85.5	105.6	92.8	89.7	95.0
08/31/98	**Mon**	**98.1**	**107.2**	**86.2**	**111.2**	**97.4**	**104.8**	**98.2**	**72.3**	**84.4**	**93.3**	**114.1**	**102.3**	**91.6**	**88.6**	**98.5**	**92.0**	**85.7**	**96.0**
09/01/98	**Tue**	**99.3**	**105.8**	**87.1**	**109.1**	**98.8**	**104.6**	**95.4**	**70.9**	**75.9**	**95.6**	**113.2**	**103.0**	**91.0**	**89.6**	**95.7**	**87.7**	**82.2**	**95.7**
09/02/98	Wed	99.9	105.9	84.1	107.0	100.5	103.0	93.4	74.6	77.9	97.4	110.0	102.1	89.6	87.3	97.3	87.4	84.3	95.1
09/03/98	Thu	101.2	102.0	83.5	105.0	100.9	102.5	98.7	78.0	83.5	98.3	106.7	101.7	89.9	86.7	98.0	88.9	89.1	95.2
09/04/98	Fri	99.4	91.6	82.3	101.8	97.9	94.8	90.8	81.5	86.9	97.1	104.1	92.6	91.1	85.3	87.9	91.6	91.7	91.5
09/05/98	Sat	98.4	93.1	82.4	99.8	93.2	88.7	88.2	80.3	88.4	93.4	99.6	81.7	91.5	84.6	87.5	90.9	93.5	89.2
Stage II Alerts Average Temps.		**101.4**	**108.1**	**88.3**	**112.9**	**98.7**	**102.1**	**92.3**	**75.1**	**78.4**	**96.1**	**115.6**	**99.2**	**90.5**	**90.5**	**102.0**	**89.0**	**80.2**	**96.0**

Source: Energy Commission staff.

Using Temperature Data to Forecast Electricity Demand

Our analysis of the temperature conditions in the summer of 1998 showed that it was a unique year when compared to historical average temperature conditions. The next step in our analysis of the relationship between temperature and electricity demand in the WSCC is to develop a forecast of hourly electricity demands for the summer of 1999 corresponding to a range of temperature conditions that have a different probability of occurrence. The staff will then evaluate the adequacy of the generation capacity in the WSCC to meet the forecasted demands corresponding to these temperature scenarios.

Correlation of Temperatures Across Western Systems Coordinating Council Sub-Regions

The first step in constructing temperature-sensitive demand scenarios is to identify, based on historical temperature and demand data, which sub-region of the WSCC has the strongest influence on the average high temperature and, on the coincident peak demand, for the entire WSCC. For planning are reporting purposes, the WSCC aggregates the loads of its member utilities into four regions: the Northwest Power Pool Area [i.e., the Pacific Northwest (PNW)], the Rocky Mountain Power Area (RMPA), the Arizona-New Mexico-Southern Nevada Power Area [i.e., the Desert Southwest (DSW)], and the California-Mexico Power Area (CAMX).

While the Northwest region's loads are the largest in the WSCC, there is a much stronger correlation between average high temperature conditions in California and the other regions of the WSCC. **Table I-3** shows that average high temperatures in California have the highest overall correlation to average high temperatures in the other WSCC sub-regions. What this means is that climatic conditions that cause high temperatures across California are also likely to have a similar effect on temperatures in the Pacific Northerwest and Desert Southwest.

TABLE I-3
Cross Correlation Coefficients
3-Day Moving Average High Temperatures

	PNW	RMPA	CAMX	DSW
PNW	1.0000	-0.1833	0.4490	0.2413
RMPA	-0.1833	1.0000	0.0542	0.3072
CAMX	0.4490	0.0542	1.0000	0.4214
DSW	0.2413	0.3072	0.4214	1.0000

Source: Energy Commission staff.

The strength of the relationship of California's temperatures to temperatures in the other WSCC regions is not surprising because California itself consists of several climate zones and its in-state temperatures resemble those of a 'mini-WSCC'. Our documentation of this relationship, however, provides the analytical justification for our ultimate choice of California temperature data to use in creating demand scenarios when we evaluate overall supply adequacy within the WSCC.

Correlation of Peak Demand and Temperature among the Western Systems Coordinating Council Sub-regions

We showed in **Table I-3** that average high temperatures in California have the strongest correlation to temperatures in the Pacific Northwest and Desert Southwest. The same relationship exists between peak demand and average high temperatures. **Table I-4** displays the cross-correlation coefficient for the 3-day moving average high temperature across the four WSCC sub-regions to that of the WSCC's summer coincident peak.

Table I-4
Pearson Correlation Coefficients
3-Day Average High Temperatures

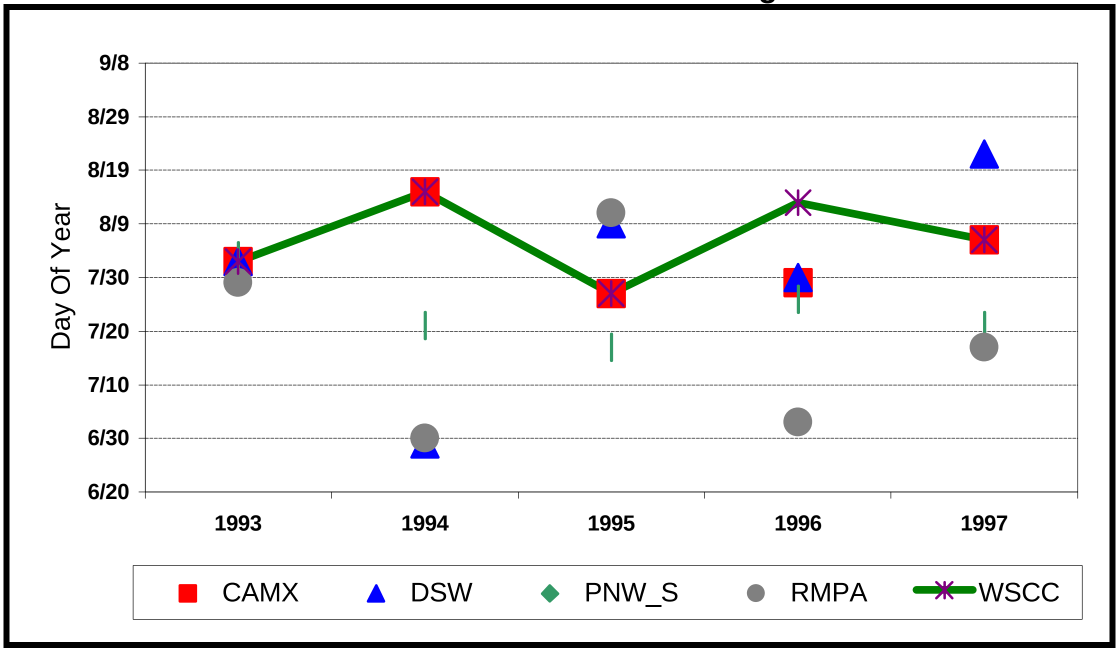
	WSCC Coincident Peak
CAMX TMAX631	0.68663
PNW TMAX631	0.49585
DSW TMAX631	0.32617
RMPA TMAX631	0.02858

Source: Energy Commission staff.

California-Mexico has the highest correlation coefficient among the regions. The timing of the WSCC coincident peak, therefore, is most likely to occur when temperatures are high in California. In forecasting hourly demands for the entire WSCC, we now know that using historical temperature data for the entire WSCC, corresponding to the days of the California coincident peak, will most likely yield a scenario that includes hot conditions across the WSCC and the WSCC coincident peak. Such a scenario will test the limits of the WSCC supply system.

For additional corroboration of the timing of the WSCC coincident peak with the peak demand in California, we plotted the WSCC coincident peak against the non-coincident peaks for the four WSCC sub-regions for the years 1993 through 1997. In four of the five years, California/Mexico peak coincides with the WSCC system peak. This coincidence in the timing of the California and WSCC peak demand is shown in **Figure I-6**.

FIGURE I-6
Coincident and Non-Coincident Summer Peak Dates
For the WSCC and Four Sub-Regions



Source: Energy Commission staff.

Assigning Probabilities to the Occurrence of High Temperatures

The next step in creating high temperature demand scenarios for the WSCC using temperature data for California was to assign a probability to the occurrence of these high temperature scenarios. In other words, what is the likelihood that a given pattern of high temperatures will occur in any year? To do this, we calculated the 3-day moving average high temperature across California for each year over the last forty years (1959-1998) for the day of the expected 1999 California peak. The expected peak day for 1999 was determined by creating a typical load shape based on historical load data for the state for the years 1993-1997.

Each year was then ranked from lowest 3-day average high temperature to highest. The year with the hottest 3-day moving average temperature across California on the peak day had a 1-in-40 probability of occurring. In addition to identifying the year with the hottest temperatures as the basis for an extreme temperature scenario, we also wanted to identify years with temperatures that had a higher probability of occurring. These temperatures would define a scenario that would be more reasonable for planning purposes. We created a 1-in-5 year probability scenario by averaging the temperatures from the years having the 7th, 8th and 9th highest temperatures on the peak day. By averaging these three years, we minimize any peculiarities, anomalies and missing data in a single year.

Assigning Chronology to Temperature Data

Using our 40 years of temperature data for each of the 17 transmission areas within the WSCC, we created 3-day average high temperatures for each day of the months June through September. The days of each of these months were then put in the order of lowest average high temperature to highest average high temperature. A similar ordering was then done of the daily high temperatures for the months in the years having a 1-in-40 and 1-in-5 probability for each transmission area

At this point, we have three sets of temperature data for 4 months for each transmission area. One set is for the months in the years corresponding to the 1-in-5 probability, one for the 1-in-40 probability and one for the average of all 40 years. The reason for creating the 40-year average set of temperatures was to identify which day of the month is on average the hottest, the second hottest, the third hottest, etc. The ranking of days by temperature ensures that when constructing the high temperature demand scenarios, we do not convert a cool day from the base case into a hot day in one of our scenarios.[10] We want to be able to compare across scenarios how sensitive demand is to changes in temperature. We preserve our ability to compare changes in peak demand due solely to changes in temperature by assigning the temperatures from the two hot weather scenarios, which are in order of lowest to highest, to the days associated with the 40 year average, which are in order of lowest to highest temperature. This procedure is illustrated in **Table I-5**.

[10] For documentation on creating typical high temperature, see staff report, *California Energy Demand 1995-2015, Volume II: Electricity Demand Forecasting Methods*, July 1995, California Energy Commission, p. 8-3.

Table I-5
Methodology for Creating Temperature Scenarios

1-in 40 SCENARIO YEAR		40-YEAR AVERAGE		MERGE SCENARIO TEMPERATURES TO 40-YEAR AVERAGE DATES	
Day Of Month From Scenario Year	Daily High Temperatures From Scenario Year (°F)	Day Of Month For 40-Year Average	Daily 40-Year Average High Temperatures (°F)	Day Of Month For 40-Year Average	Daily High Temperatures From Scenario Year (°F)
18	81.8	31	85.0	31	81.8
17	83.5	30	85.5	30	83.5
16	84.4	19	85.5	19	84.4
19	85.8	27	85.7	27	85.8
26	86.1	26	85.8	26	86.1
25	86.6	18	85.8	18	86.6
1	87.2	23	85.8	23	87.2
15	87.2	24	85.9	24	87.2
23	87.4	25	85.9	25	87.4
24	87.8	20	85.9	20	87.8
7	88.0	21	86.1	21	88.0
21	88.1	22	86.1	22	88.1
20	88.3	17	86.3	17	88.3
27	89.6	15	86.3	15	89.6
8	90.0	16	86.4	16	90.0
6	90.2	29	86.5	29	90.2
22	90.4	28	86.5	28	90.4
10	91.6	14	86.9	14	91.6
9	91.8	13	87.3	13	91.8
2	93.0	12	88.1	12	93.0
11	93.2	4	88.6	4	93.2
14	93.2	11	88.7	11	93.2
28	93.6	5	88.7	5	93.6
5	94.0	2	88.8	2	94.0
12	94.9	1	88.9	1	94.9
30	95.1	3	89.0	3	95.1
29	95.2	10	89.0	10	95.2
3	95.8	6	89.6	6	95.8
13	95.9	9	89.8	9	95.9
31	96.6	7	89.8	7	96.6
4	96.6	8	90.1	8	96.6

Source: Energy Commission staff.

Forecasting Peak Demands

To assess supply adequacy in the WSCC under our two hot weather scenarios, the staff had to forecast daily peak demands for the 17 transmission areas within the WSCC. The principal obstacle to forecasting daily peak demand was that, with the exception of the California transmission areas a 3-day moving average temperature statistic was the only explanatory variable for which we had complete data. Most peak demand forecast models that capture the relationship between daily peak demand and high temperatures require additional, non-temperature data such as regional differences in prices, customer mix (i.e., residential, commercial, and agricultural sectors) and number of customers.

We found that the more traditional models did not explain the variations exhibited in the daily peaks very well. For example, a simple linear regression model that regress daily maximum load on moving averages of daily maximum temperatures and a dummy variable used to capture non-temperature effects resulted in R-Squares of less than 0.50. We solved the problem of having only one variable by using a mixed fixed/random coefficient model, which better explains the variation in the dependent variable when only one independent variable is available. This model treats the non-temperature effects on demand as fixed across time and different across transmission areas. The temperature effects are assumed to come from common response across transmission areas, then adjusted to the unique high temperature ranges in each transmission area.[11] This model provides an estimate of the temperature-induced demand response, which we then used to predict the change in daily peak demand from a base case demand forecast submitted by the utilities for the year 1999. We assumed that these base case demand forecasts submitted by the utilities are based on average temperature conditions.

The mixed fixed/random model had the following functional form:

$$\mathbf{LDMWhMax_{td} = Dummy_{ty} + (\alpha_m + \beta_{tm})*LTMax631_{td}}$$

Where: LDMWhMax is the natural log of daily peaks
LTMax631 is the natural log of 3-day moving average temperatures
Dummy is the variable used to capture non-temperature effects
α is the mean temperature response across all transmission areas
β is the adjustment to the mean response unique to each transmission area
t is the transmission area subscript 1-17
d is the daily subscript 1-122
m is the monthly subscript, June through September
y is the yearly subscript, 1993 - 1997

Table I-6 displays the average response coefficient estimated by the model. **Table I-7** provides the adjustment response coefficient for each of the 17 transmission areas. Because we ran the model on the natural logs of the dependent and independent variables, the temperature response coefficients can be interpreted as elasticities. The elasticity coefficients unique to each transmission area were determined by adding the adjustment coefficients to the average response coefficients.

To get the change in peak demand from the base case corresponding to the change in temperature in our two scenarios, we derived the percentage change in the 3-day moving average high temperatures by transmission area for each day of the summer months June through September. The daily percentage change in temperature from the base case to the 1-in-5 scenario, and base case to the 1-in-40 scenario, was then multiplied by the temperature-related demand elasticity coefficients from the mixed fixed/random model to produce the percentage change in load. The daily peak load in the base case was then multiplied by one plus the percentage change in daily peak load (i.e. 1 + 0.08) to produce the daily peak loads for each scenario.

[11] Technically, the model allows the temperature effects to vary across transmission areas and over time, but it pools the data to estimate how temperature affects the areas' load as a group. By incorporating individual regional effects, the model captures variation in load due to differences among transmission areas and produces consistent and efficient estimation of the effects across the 17 transmission areas. For modeling specifics, see *SAS® System for Mixed Models*, 1996.

TABLE I-6
AVERAGE RESPONSE COEFFICIENT

Month of Year	Temperature Response Coefficients	Standard Error	T-Statistic
6	0.8161	0.1483	5.50
7	0.8220	0.1483	5.54
8	0.8240	0.1483	5.56
9	0.8195	0.1483	5.53

Source: Energy Commission staff.

TABLE I-7
Adjustment Response Coefficient

Tranmission Area	Month of Year	Adjustment Response Coefficients	Standard Error	T-Statistic
Alberta	6	-0.6964	0.1493	-4.670
Alberta	7	-0.7002	0.1492	-4.690
Alberta	8	-0.7032	0.1492	-4.710
Alberta	9	-0.6963	0.1493	-4.670
Arizona	6	0.7841	0.1518	5.170
Arizona	7	0.7928	0.1517	5.220
Arizona	8	0.8018	0.1518	5.280
Arizona	9	0.7984	0.1519	5.260
BCHA	6	-0.7319	0.1498	-4.890
BCHA	7	-0.7366	0.1497	-4.920
BCHA	8	-0.7396	0.1497	-4.940
BCHA	9	-0.7298	0.1497	-4.870
CFE	6	0.0265	0.1526	0.170
CFE	7	0.0314	0.1525	0.210
CFE	8	0.0373	0.1525	0.240
CFE	9	0.0341	0.1526	0.220
CNORTH	6	0.5294	0.1502	3.520
CNORTH	7	0.5335	0.1501	3.550
CNORTH	8	0.5295	0.1501	3.530
CNORTH	9	0.5214	0.1502	3.470
CSCE	6	0.5748	0.1508	3.810
CSCE	7	0.5692	0.1507	3.780
CSCE	8	0.5695	0.1507	3.780
CSCE	9	0.5676	0.1507	3.770
CSDGE	6	0.0967	0.1507	0.640
CSDGE	7	0.0909	0.1507	0.600
CSDGE	8	0.1005	0.1506	0.670
CSDGE	9	0.1076	0.1507	0.710
CSF	6	-0.8242	0.1501	-5.490
CSF	7	-0.8314	0.1501	-5.540
CSF	8	-0.8296	0.1500	-5.530
CSF	9	-0.8223	0.1501	-5.480

(continued on next page)

TABLE I-7 (continued)
Adjustment Response Coefficient

Tranmission Area	Month of Year	Adjustment Response Coefficients	Standard Error	T-Statistic
Colorado	6	-0.2528	0.1493	-1.690
Colorado	7	-0.2515	0.1493	-1.680
Colorado	8	-0.2498	0.1493	-1.670
Colorado	9	-0.2526	0.1494	-1.690
ID-SPP	6	-0.2088	0.1495	-1.400
ID-SPP	7	-0.2074	0.1495	-1.390
ID-SPP	8	-0.2200	0.1495	-1.470
ID-SPP	9	-0.2249	0.1495	-1.500
IID	6	0.9504	0.1518	6.260
IID	7	0.9464	0.1518	6.240
IID	8	0.9438	0.1517	6.220
IID	9	0.9509	0.1518	6.260
LADWP	6	0.5224	0.1505	3.470
LADWP	7	0.5157	0.1505	3.430
LADWP	8	0.5167	0.1504	3.430
LADWP	9	0.5134	0.1505	3.410
NewMexico	6	-0.1680	0.1512	-1.110
NewMexico	7	-0.1674	0.1511	-1.110
NewMexico	8	-0.1639	0.1512	-1.080
NewMexico	9	-0.1654	0.1513	-1.090
Northwest	6	-0.6055	0.1499	-4.040
Northwest	7	-0.6087	0.1498	-4.060
Northwest	8	-0.6130	0.1498	-4.090
Northwest	9	-0.6121	0.1498	-4.090
SoNevada	6	0.9420	0.1508	6.250
SoNevada	7	0.9413	0.1507	6.250
SoNevada	8	0.9433	0.1507	6.260
SoNevada	9	0.9444	0.1508	6.260
Utah	6	-0.3965	0.1495	-2.650
Utah	7	-0.3887	0.1495	-2.600
Utah	8	-0.3905	0.1495	-2.610
Utah	9	-0.3930	0.1495	-2.630
Wyoming	6	-0.5423	0.1491	-3.640
Wyoming	7	-0.5294	0.1491	-3.550
Wyoming	8	-0.5328	0.1491	-3.570
Wyoming	9	-0.5414	0.1492	-3.630

Source: Energy Commission staff.

Table I-8 displays how well the fixed/random model explains the variations in daily peak loads by transmission area.

TABLE I-8
Fit of the Model

Transmission Area	R-Square
Alberta	0.8805
Arizona	0.9102
BCHA	0.8027
CFE	0.8196
CNORTH	0.9121
CSCE	0.9206
CSDGE	0.8457
CSF	0.9228
Colorado	0.8850
ID-SPP	0.8661
IID	0.7672
LADWP	0.8996
NewMexico	0.8744
Northwest	0.8432
SoNevada	0.9423
Utah	0.8979
Wyoming	0.8263

Source: Energy Commission staff.

Sensitivity of Peak Demand to Changes in Temperature

Table I-9 shows how sensitive peak demand is to small changes in average temperatures. In the 1-in-40 year temperature scenario, the 3-day average high temperature on the day of the California coincident peak is 5 degrees hotter than the base case, but this increase in temperature translates into an additional load of approximately 4,000 MW in the California ISO control area.

TABLE I-9
Changes in Coincident Peak Demand (MW)
Resulting From High Temperature Scenarios

Scenario	California Temperature	WSCC Peak	% Change From Base Case	CA/MX Peak	% Change From Base Case	Cal ISO Peak	% Change From Base Case
Base Case is One In 2 1/2	91.1	126,552	----	53,939	----	45,584	----
One In Five	93.5	128,426	1.5%	55,800	3.5%	47,115	3.4%
One In Ten	94.9	130,266	2.9%	57,028	5.7%	48,277	5.9%
One In Forty	96.0	131,634	4.0%	58,280	8.0%	49,473	8.5%

Source: Energy Commission staff.

Table I-10 and **Table I-11** show the change in annual peak loads, by transmission area, for the two scenarios.

TABLE I-10
Comparison of Transmission Area Peak Demand
Base Case to Hot In California, 1-in-5 Year Probability

Transmission Area	Base Case Peak Date	Base Case Weekday	Base Case Peak (MW)	Scenario 1 Peak Date	Scenario 1 Weekday	Scenario 1 Peak (MW)	Percent Change Scenario/Base
Alberta	3-Aug	Tuesday	6,997	27-Aug	Friday	7,022	0.4%
Arizona	7-Jul	Wednesday	11,783	7-Jul	Wednesday	11,809	0.2%
BCHA	27-Sep	Monday	7,474	27-Sep	Monday	7,460	-0.2%
CFE	12-Aug	Thursday	1,535	26-Aug	Thursday	1,558	1.5%
CNORTH	12-Aug	Thursday	20,181	12-Aug	Thursday	20,938	3.8%
CSCE	2-Sep	Thursday	21,201	12-Aug	Thursday	21,900	3.3%
CSDGE	2-Sep	Thursday	3,776	18-Aug	Wednesday	3,801	0.7%
CSF	18-Jun	Friday	943	18-Jun	Friday	943	0.0%
Colorado	21-Jul	Wednesday	7,112	21-Jul	Wednesday	7,091	-0.3%
ID-SPP	26-Jul	Monday	4,866	26-Jul	Monday	4,870	0.1%
IID	31-Aug	Tuesday	725	1-Sep	Wednesday	746	2.9%
LADWP	12-Aug	Thursday	6,176	12-Aug	Thursday	6,479	4.9%
NewMexico	19-Aug	Thursday	3,270	18-Aug	Wednesday	3,282	0.4%
Northwest	11-Aug	Wednesday	23,929	29-Jul	Thursday	23,958	0.1%
SoNevada	12-Aug	Thursday	4,582	10-Aug	Tuesday	4,652	1.5%
Utah	26-Jul	Monday	4,259	26-Jul	Monday	4,217	-1.0%
Wyoming	19-Jul	Monday	1,802	19-Jul	Monday	1,818	0.9%

Source: Energy Commission staff.

TABLE I-11
Comparison of Transmission Area Peak Demand
Base Case to Hot In California 1-in 40 Year Probability

Transmission Area	Base Case Peak Date	Base Case Weekday	Base Case Peak (MW)	Scenario 2 Peak Date	Scenario 2 Weekday	Scenario 2 Peak (MW)	Percent Change Scenario/Base
Alberta	3-Aug	Tuesday	6,997	3-Aug	Tuesday	7,033	0.5%
Arizona	7-Jul	Wednesday	11,783	17-Aug	Tuesday	12,411	5.3%
BCHA	27-Sep	Monday	7,474	27-Sep	Monday	7,531	0.8%
CFE	12-Aug	Thursday	1,535	26-Aug	Thursday	1,555	1.3%
CNORTH	12-Aug	Thursday	20,181	12-Aug	Thursday	22,123	9.6%
CSCE	2-Sep	Thursday	21,201	12-Aug	Thursday	23,074	8.8%
CSDGE	2-Sep	Thursday	3,776	18-Aug	Wednesday	3,801	0.7%
CSF	18-Jun	Friday	943	18-Jun	Friday	943	0.0%
Colorado	21-Jul	Wednesday	7,112	20-Jul	Tuesday	7,237	1.8%
ID-SPP	26-Jul	Monday	4,866	26-Jul	Monday	4,901	0.7%
IID	31-Aug	Tuesday	725	18-Aug	Wednesday	789	8.8%
LADWP	12-Aug	Thursday	6,176	11-Aug	Wednesday	6,603	6.9%
NewMexico	19-Aug	Thursday	3,270	21-Jul	Wednesday	3,416	4.5%
Northwest	11-Aug	Wednesday	23,929	28-Jul	Wednesday	24,189	1.1%
SoNevada	12-Aug	Thursday	4,582	18-Aug	Wednesday	4,994	9.0%
Utah	26-Jul	Monday	4,259	26-Jul	Monday	4,268	0.2%
Wyoming	19-Jul	Monday	1,802	19-Jul	Monday	1,805	0.2%

Source: Energy Commission staff.

Forecasting Hourly Loads from Peak Demand

Deriving hourly loads for each of the scenarios was also a two-step process. First, daily load factors[12] were calculated using the forecasted base case loads for 1999 for each transmission area. The forecasted peak demand for each scenario was then entered into the load factor equation to derive daily total load. We then multiplied the daily total load by the percent of daily use in each hour to create hourly loads.[13] These hourly loads for the months June through September for 1999 for the base case, 1-in-5 and 1-in-40, temperature scenarios were then placed into a utility simulation model for evaluating supply adequacy. (The supply adequacy analysis is discussed in the next section of this report.)

Summary of Findings

An examination of historical temperature data for the western states in the WSCC from the last 40 years revealed the following:

- Only one other year in the last 40, 1985, had as many days where temperatures were as hot as those that occurred last summer.

- The 3-day moving average high temperature for the WSCC on the weekdays when the ISO declared a Stage II alert was over 95°F. In the past 40 years, the average high temperature for the entire WSCC exceeded 95°F on only 31 weekdays. The probability that four would occur in a single year is 1-in-50.

- When hot temperatures prevailed across California in 1999, two of the three regions of the WSCC, the Pacific Northwest and the Desert Southwest, also experience high temperatures. There is also a strong correlation between the timing of peak demand in the California and the peak demand for the entire WSCC.

The staff used historical temperature and demand data for 67 utility service areas within the WSCC to derive two high temperature forecasts of electricity demand in the WSCC for the summer of 1999. One forecast assumed temperature conditions corresponding to a 1-in-40 year probability, (i.e., similar to the temperature conditions that occurred in the 1998). The other forecast assumed temperature conditions corresponding to a 1-in-5 year probability. These two hot weather demand scenarios—along with a forecast of demand for the WSCC under average, or expected—temperature conditions, provided the basis for the staff's evaluation of supply adequacy.

Peak demand is very sensitive to small changes in average high temperatures. On the day of the California coincident peak, the 3-day average high temperature for the ISO control area in the 1-in-40 year scenario was five-degrees hotter than the base case. Peak demand for the ISO area in the 1-in-40 scenario, however, increased by approximately 4,000 MWs, which was 8.5 percent higher than the expected peak.

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[12] Daily Load Factor = Total Daily Load (MWh) ÷ (Daily Peak (MW)*24)

[13] The percent of daily use in each hour by utility was derived from the average load shapes. The load shapes for the 67 utilities were created using historical hourly load data for each utility for the years over 1993 through 1997.

Appendix I

Mapping of Utility Region to Weather Station

State	Utility Region Name	Weather Station Cite
AB	Trans Alta Utilities Corp.	Lewiston, Idaho
AZ	Arizona Electric Power Cooperative Inc.	Tucson, Arizona
AZ	Arizona Public Service Company	Phoenix, Arizona
AZ	Citizens Utilities Company Arizona	Tucson, Arizona
AZ	Navajo Tribal Utility Authority	Winlsow, Arizona
AZ	Salt River Project Agricultural Improvement	Phoenix, Arizona
AZ	Tucson Electric Power Company	Tucson, Arizona
BC	British Columbia Hydro & Power Authority--Canada	Seattle, Washington
BC	West Kootenay--Canada	Lewiston, Idaho
CA	Anaheim Public Utilities Department	Los Angeles, California--Civic Center
CA	Burbank Public Service Department	Burbank, California
CA	Department Of Water Resources--North	Main Regional Average
CA	Department Of Water Resources--South	SCE Regional Average
CA	Glendale Public Service Department	Burbank, California
CA	Imperial Irrigation District	Palm Springs, California
CA	Los Angeles Department of Water & Power Region	LADWP Regional Average
CA	Metropolitan Water District Of Southern California	Los Angeles, California--Civic Center
CA	Modesto Irrigation District	Modesto, California
CA	Northern California Power Agency	NCPA Regional Average
CA	Pacific Gas & Electric--Main	Main Regional Average
CA	Pacific Gas & Electric--San Francisco	San Francisco, California--WSO
CA	Pacific Gas & Electric--South	Fresno, California
CA	Pasadena Water and Power Department	Pasadena, California
CA	Redding Electric Department	Redding, California
CA	Riverside Utilities Department	Riverside, California
CA	Sacramento Municipal Utilities District	Sacramento, California--WSO Site
CA	San Diego Gas & Electric	El Cajon, California
CA	Santa Clara Electric Department	San Jose, California
CA	Southern California Edison Region	SCE Regional Average
CA	Turlock Irrigation District	Turlock, California
CA	Vernon Municipal Light Department	Los Angeles, California--Civic Center
CA	WAPA-Mid Pacific (CVP)	Main Regional Average
CO	Colorado Springs Utilities	Colorado Springs, Colorado
CO	Platte River Power Authority	Colorado Springs, Colorado
CO	Public Service Of Colorado	Colorado Springs, Colorado
CO	Tri-State G&T In PSCo	Pueblo, Colorado
CO	Tri-State G&T In WAUC	Grand Junction, Colorado
CO	West Plains Energy	Pueblo, Colorado
ID	Idaho Power Company	Boise, Idaho
ID	Pacific Corp.--Idaho	Boise, Idaho
MT	Montana Power Company	Helena, Montana
MX	Commission Federal de Electricidad--Mexico	El Centro, California
NM	City of Farmington	Los Alamos, New Mexico
NM	El Paso Electric Department	Carlsbad, New Mexico
NM	Los Alamos County	Los Alamos, New Mexico
NM	Plains Electric G & T Cooperative, Inc.	Carlsbad, New Mexico
NM	Public Service Company Of New Mexico	Albuquerque, New Mexico
NM	Texas New Mexico Power Region	Carlsbad, New Mexico
NV	Nevada Power Company	Las Vegas, Nevada
NV	Sierra Pacific Power Company	Reno, Nevada
NV	WAPA-Lower Colorado	Las Vegas, Nevada
OR	Eugene Water & Electric Board	Eugene, Oregon
OR	Pacifi Corp.--NorthWest	Eugene, Oregon
OR	Portland General Electric	Portland, Oregon
SD	Black Hills Power & Light	Newcastle, Wyoming
UT	Desert Generation Transmission Cooperative	Salt Lake City, Utah
UT	Pacific Corp.--Utah	Salt Lake City, Utah
UT	Utah Associated Municipal Power Systems	Salt Lake City, Utah
UT	Utah Municipal Power Agency	Salt Lake City, Utah
UT	WAPA-Upper Colorado	Salt Lake City, Utah
WA	Bonneville Power Administration Control Area	Seattle, Washington
WA	PUD No. 1 Of Chelan County	Wenatchee, Washington
WA	PUD No. 1 Of Douglas County	Wenatchee, Washington
WA	PUD No. 1 Of Grant County	Wenatchee, Washington
WA	Puget Sound Power & Light	Seattle, Washington
WA	Seattle City Light	Seattle, Washington
WA	Tacoma Public Utilities	Seattle, Washington
WA	Washington Water Power Company	Spokane, Washington
WY	Basin Electric Cooperative	Newcastle, Wyoming
WY	Pacific Corp.--Wyoming	Cheyenne, Wyoming
WY	Tri-State G&T In Wyoming	Cheyenne, Wyoming
WY	WAPA--Lower Missouri	Cheyenne, Wyoming

Mapping of Utility Service Region to Transmission Area to Power Pool

State	Utility Region Name	Transmission Area Name	Abbr.		Abbr.
CA	Imperial Irrigation District	Imperial Irrigation District Region	IID	California-Mexico	CAMX
CA	Burbank Public Service Department	Los Angeles, California Region	LADWP	California-Mexico	CAMX
CA	Glendale Public Service Department	Los Angeles, California Region	LADWP	California-Mexico	CAMX
CA	Los Angeles Department of Water& Power Region	Los Angeles, California Region	LADWP	California-Mexico	CAMX
CA	Pasadena Water and Power Department	Los Angeles, California Region	LADWP	California-Mexico	CAMX
CA	Department Of Water Resources-North	Northern California Region	CNORTH	California-Mexico	CAMX
CA	Modesto Irrigation District	Northern California Region	CNORTH	California-Mexico	CAMX
CA	Northern California Power Agency	Northern California Region	CNORTH	California-Mexico	CAMX
CA	Pacific Gas & Electric-Main	Northern California Region	CNORTH	California-Mexico	CAMX
CA	Redding Electric Department	Northern California Region	CNORTH	California-Mexico	CAMX
CA	Sacramento Municipal Utilities District	Northern California Region	CNORTH	California-Mexico	CAMX
CA	Santa Clara Electric Department	Northern California Region	CNORTH	California-Mexico	CAMX
CA	Turlock Irrigation District	Northern California Region	CNORTH	California-Mexico	CAMX
CA	WAPA-Mid Pacific (CVP)	Northern California Region	CNORTH	California-Mexico	CAMX
CA	San Diego Gas & Electric	San Diego, California Region	CSDGE	California-Mexico	CAMX
CA	Pacific Gas & Electric--SanFrancisco	San Francisco, California Region	CSF	California-Mexico	CAMX
CA	Anaheim Public Utilities Department	Southern California Edison Region	CSCE	California-Mexico	CAMX
CA	Department Of Water Resources-North	Southern California Edison Region	CSCE	California-Mexico	CAMX
CA	Metropolitan Water District Of Southern California	Southern California Edison Region	CSCE	California-Mexico	CAMX
CA	Pacific Gas & Electric--South	Southern California Edison Region	CSCE	California-Mexico	CAMX
CA	Riverside Utilities Department	Southern California Edison Region	CSCE	California-Mexico	CAMX
CA	Southern California Edison Region	Southern California Edison Region	CSCE	California-Mexico	CAMX
CA	Vernon Municipal Light Department	Southern California Edison Region	CSCE	California-Mexico	CAMX
MX	Commission Federal de Electricidad--Mexico	Nothern Baja Mexico Region	CFE	California-Mexico	CAMX
AZ	Arizona Electric Power Cooperative Inc.	Arizona Region	Arizona	Desert Southwest	DSW
AZ	Arizona Public Service Company	Arizona Region	Arizona	Desert Southwest	DSW
AZ	Citizens Utilities Company Arizona	Arizona Region	Arizona	Desert Southwest	DSW
AZ	Navajo Tribal Utility Authority	Arizona Region	Arizona	Desert Southwest	DSW
AZ	Salt River Project Agricultural	Arizona Region	Arizona	Desert Southwest	DSW
AZ	Tucson Electric Power Company	Arizona Region	Arizona	Desert Southwest	DSW
NM	City of Farmington	New Mexico Region	NewMexico	Desert Southwest	DSW
NM	El Paso Electric Department	New Mexico Region	NewMexico	Desert Southwest	DSW
NM	Los Alamos County	New Mexico Region	NewMexico	Desert Southwest	DSW
NM	Plains Electric G&T Cooperative, Inc.	New Mexico Region	NewMexico	Desert Southwest	DSW
NM	Public Service Company Of New Mexico	New Mexico Region	NewMexico	Desert Southwest	DSW
NM	Texas New Mexico Power Region	New Mexico Region	NewMexico	Desert Southwest	DSW
NV	Nevada Power Company	Southern Nevada Region	SoNevada	Desert Southwest	DSW
NV	WAPA-LowerColorado	Southern Nevada Region	SoNevada	Desert Southwest	DSW
AB	Trans Alta Utilities Corp.	Alberta, Canada Region	Alberta	Pacific Northwest	PNW
BC	British Columbia Hydro & Power Authority--	British Columbia Canada Region	BCHA	Pacific Northwest	PNW
BC	West Kootenay--Canada	British Columbia Canada Region	BCHA	Pacific Northwest	PNW
ID	Idaho Power Company	Idaho/Sierra Pacific Power Region	ID-SPP	Pacific Northwest	PNW
ID	Pacific Corp.--Idaho	Idaho/Sierra Pacific Power Region	ID-SPP	Pacific Northwest	PNW
NV	Sierra Pacific Power Company	Idaho/Sierra Pacific Power Region	ID-SPP	Pacific Northwest	PNW
OR	Eugene Water & Electric Board	Northern California Region	Northwest	Pacific Northwest	PNW
WA	Tacoma Public Utilities	Northern California Region	Northwest	Pacific Northwest	PNW
WA	Bonneville Power Administration Control	Northwestern United States Region	Northwest	Pacific Northwest	PNW
MT	Montana Power Company	Northwestern United States Region	Northwest	Pacific Northwest	PNW
OR	Pacifi Corp.--NorthWest	Northwestern United States Region	Northwest	Pacific Northwest	PNW
OR	Portland General Electric	Northwestern United States Region	Northwest	Pacific Northwest	PNW
WA	PUD No. 1 Of Chelan County	Northwestern United States Region	Northwest	Pacific Northwest	PNW
WA	PUD No. 1 Of Douglas County	Northwestern United States Region	Northwest	Pacific Northwest	PNW
WA	PUD No. 1 Of Grant County	Northwestern United States Region	Northwest	Pacific Northwest	PNW
WA	Puget Sound Power & Light	Northwestern United States Region	Northwest	Pacific Northwest	PNW
WA	Seattle City Light	Northwestern United States Region	Northwest	Pacific Northwest	PNW
WA	Washington Water Power Company	Northwestern United States Region	Northwest	Pacific Northwest	PNW
UT	Desert Generation Transmission Cooperative	Utah Region	Utah	Pacific Northwest	PNW
UT	Pacific Corp.--Utah	Utah Region	Utah	Pacific Northwest	PNW
UT	Utah Associated Municipal Power Systems	Utah Region	Utah	Pacific Northwest	PNW
UT	Utah Municipal Power Agency	Utah Region	Utah	Pacific Northwest	PNW
UT	WAPA-UpperColorado	Utah Region	Utah	Pacific Northwest	PNW
CO	Colorado Springs Utilities	Colorado Region	Colorado	Rocky Mountians	RMPA
CO	Platte River Power Authority	Colorado Region	Colorado	Rocky Mountians	RMPA
CO	Public Service Of Colorado	Colorado Region	Colorado	Rocky Mountians	RMPA
CO	Tri-State G&T In PSCo	Colorado Region	Colorado	Rocky Mountians	RMPA
CO	Tri-State G&T In WAUC	Colorado Region	Colorado	Rocky Mountians	RMPA
CO	West Plains Energy	Colorado Region	Colorado	Rocky Mountians	RMPA
WY	Basin Electric Cooperative	Wyoming Region	Wyoming	Rocky Mountians	RMPA
SD	Black Hills Power & Light	Wyoming Region	Wyoming	Rocky Mountians	RMPA
WY	Pacific Corp.--Wyoming	Wyoming Region	Wyoming	Rocky Mountians	RMPA
WY	Tri-State G&T In Wyoming	Wyoming Region	Wyoming	Rocky Mountians	RMPA
WY	WAPA--Lower Missouri	Wyoming Region	Wyoming	Rocky Mountians	RMPA

Source: Energy Commission staff.

Section II: Supply Adequacy

This section addresses the question of whether there is enough generation capacity in California and the rest of the WSCC to meet the peak demand and hourly loads forecasted in our two high temperature scenarios, as well as provide for an adequate margin of excess capacity above demand for reliability. We begin with a description of the computer model that we used to evaluate supply adequacy in California and the WSCC. We identify critical input assumptions to the model and describe how the WSCC network of generators, transmission lines and load centers are characterized within the model. The results from the model are then presented. These results include an assessment of supply adequacy to meet expected demand levels under average temperature conditions and under our two hot weather scenarios. This section concludes with a summary of findings.

Background

To assess the adequacy of supply in the WSCC for meeting the summer demands in 1999 under expected temperature conditions and our two, hotter than expected, temperature scenarios, we used Multisym™[14], which is a computer simulation model that emulates the commitment and dispatch of generators and the transmission of electricity throughout the WSCC. The model uses a transport, or "contract path" emulation of transmission, which represents the contractual or ownership entitlements of a utility on a transmission line.[15] While the model allows for bid-based dispatch, for this study, the dispatch of units was based on their variable operating cost. In general, the dispatch of units was optimized on a region-wide basis, except in the case where there was a local area reliability constraint that required that a certain percentage of load in an area be met by local generating units.

The staff notes that using variable operating cost as the basis for dispatch may not accurately reflect the dispatch of units when capacity is limited. During such periods, some generators are likely to engage in opportunity cost bidding. Owners of multiple generating units may, under these circumstances, also find it to their advantage to withhold capacity from the market. Strategic withholding of capacity to drive prices up would obviously have a detrimental effect on reliability when demand is high and available generating capacity is limited. We have not attempted to capture the effect of withholding capacity into our modeling, but it is a factor to be kept in mind when reviewing the results of our analysis.

Load Assumptions

The first section of this report describes the methodology used to develop hourly load data for the two hot weather scenarios. For comparison purposes, a base case scenario was also run in Multisym™, which represents demand corresponding to average, or expected, temperatures. In each of the scenarios, the loads for each of the transmission areas in the WSCC are the sum of

[14] Multisym™ is a licensed product of Henwood Energy Services, Inc.
[15] A limitation of contract-path emulation is that contractual power flows may result in a particular line being congested. An alternative approach requires the use of a transmission-oriented production simulation model that redispatches generators if congestion occurs. The advantage of contract-path emulation is that it is computationally fast. We believe that, for the purposes of this analysis, it provides a reasonably accurate accounting of imports into and out of the State.

the loads of the individual utilities, including the loads of self-generators and direct access customers, within that transmission area.[16]

Hourly loads in the 1999 base case were developed for each of the 67 utilities represented in the model based on (a) an average of hourly EEI[17] load data from 1993 through 1997 and (b) 1999 peak and energy forecasts for each utility. These forecasts were taken primarily from the 1997 FERC Form 714. For utilities that did not file these data with the FERC, the 1999 annual peak and energy forecast come from one of the following sources: the Energy Commission's *1998 Baseline Energy Outlook*, the WSCC EIA-411, the individual utilities, or estimates based on historic data.

Table II-1 below compares the non-coincident peaks for our 1999 base case forecast and the two high temperature scenarios. For our evaluation of supply adequacy, however, we focused on the week that the coincident peak demand for the entire state was forecasted to occur, which is the second week of August. **Figures II-2** through **II-4** depict the loads for this week for our three scenarios and the corresponding 3-day moving average high temperatures.

Table II-1
Non-Coincident Peak Demand
for California Utilities and the ISO Control Area
(MW)

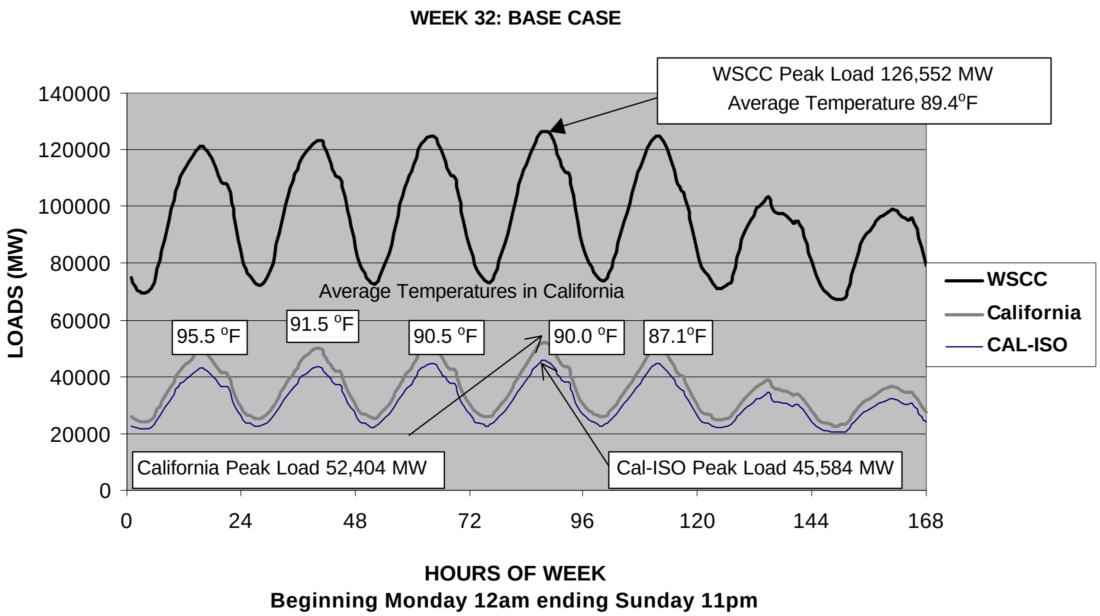
Area	1999 Base	Cal Hot 5	Cal Hot 40
Southern California Edison	19,563	20,208	21,290
San Diego Gas & Electric	3,776	3,801	3,801
Los Angeles DWP*	6,176	6,479	6,603
Pacific Gas & Electric	19,536	20,286	21,377
Sacramento MUD	2,479	2,575	2,721
No.California Power Agency	695	712	752
Imperial Irrigation District*	725	746	789
California ISO**	45,584	47,115	49,474
WSCC	126,552	128,426	131,634

* SMUD, No. Cal. Power Agency, LADWP and IID are not part of the California ISO
** ISO totals do not equal the sum of the member utility peak demands shown as they are non-coincident peaks. For planning purposes the ISO includes SMUD and NCPA loads as part of their control area.

Source: Energy Commission staff.

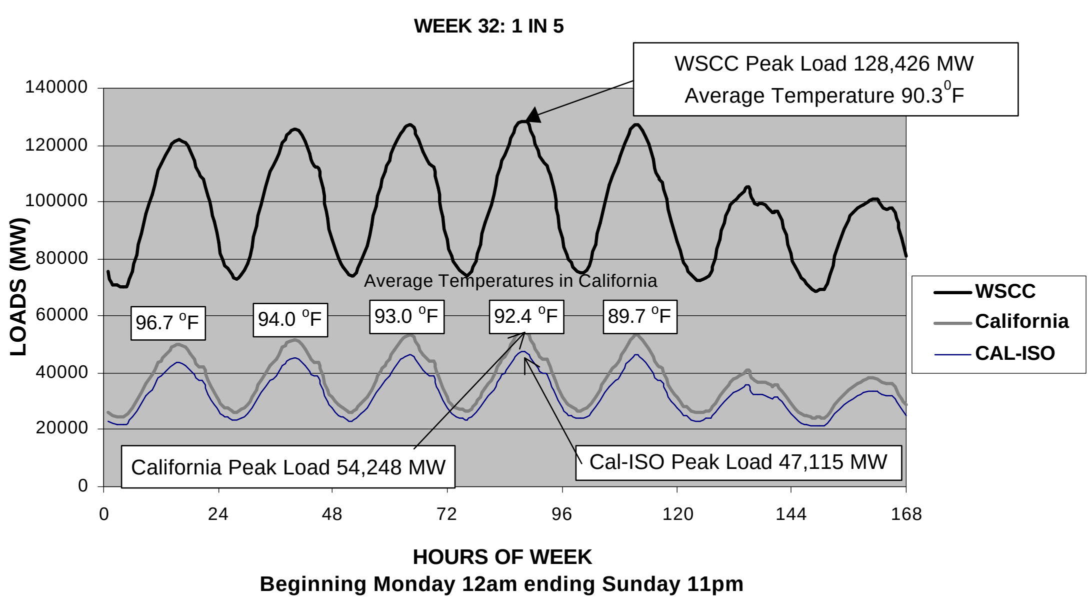
[16] Where a utility serves load in more than one transmission area, the hourly loads were either (a) distributed among the transmission areas on a *pro rata* basis or (b) where historical data was available, load shapes were developed for each transmission area.
[17] EEI- Edison Electric Institute

Figure II-1



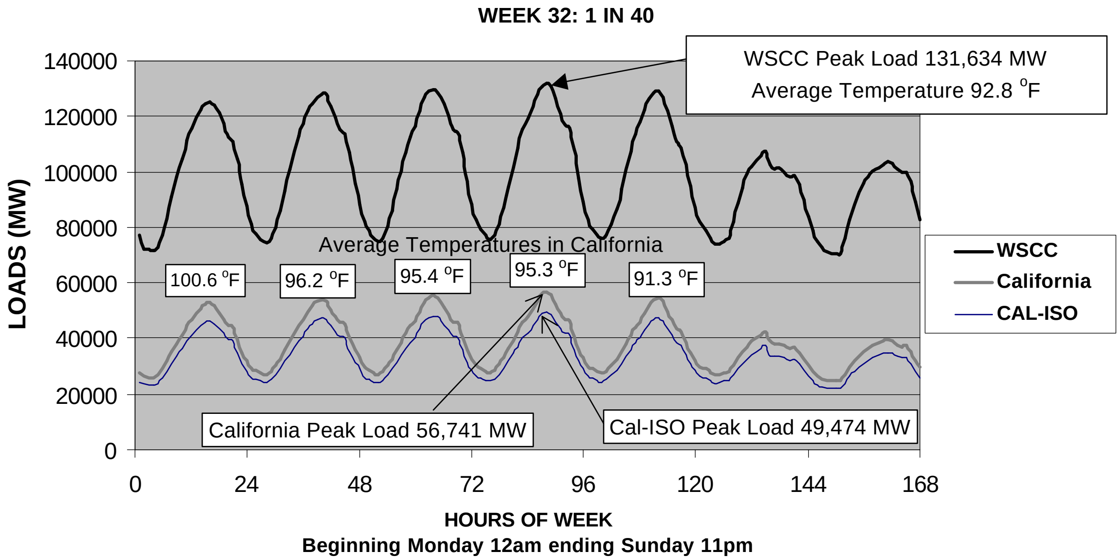
Source: Energy Commission staff.

Figure II-2



Source: Energy Commission staff.

Figure-II-3



Source: Energy Commission staff.

Generation Capacities and Commitment Status

The data on generation capacities and operating characteristics for all of the plants within the WSCC came from a variety of sources, which are listed at the end of this section. Seasonal capacity ratings, if available, were used for all units. Nuclear, geothermal and qualifying facilities were designated as must-run units. This designation means that they were always committed and dispatched at least at their minimum operating levels. They are never turned off (except when forced out or on maintenance). Some of the larger coal units were modeled as must-run units. Oil and gas-fired units are committed and dispatched in economic order unless they were needed to maintain local reliability.

Hydro availability in the Pacific Northwest was based on data provided by the Northwest Power Planning Council[18]. The data represent average water conditions. The monthly availability reflects the regulations, adopted in 1995, governing releases for salmon. The Northern California hydro availability is also based on average, or expected water conditions, and is based on data provided by PG&E in their 1996 General Rate Case. All other hydro data is a median, or average value, based on historical data.

The Transmission Network

In Multisym™, the WSCC is represented as nineteen transmission areas. **Figure II-4** depicts the topology of the WSCC in the model. All but two of these transmission areas have associated load and generation. The California-Oregon Border area is a transmission hub, lacking both load and generation, while the Palo Verde area contains the three Palo Verde nuclear units, but has no associated load. Each of the remaining transmission areas contains generation facilities and load

[18] Provided by Peter Swartz, NWPPC

served by one or more utilities. Between transmission areas are links which represent both the physical capacity of transmission lines between areas as well as the entitlements of the utilities in the transmission areas to the capacity. The capacities of these links are provided in **Table II-2**. These links are bi-directional and have associated losses. Many of the links are recognized transmission paths contained within the WSCC Path Rating Catalogue. The operating transfer capability (OTC) of these paths changes seasonally. For our analysis, we used the proposed summer of 1999 OTC ratings for the major paths leading into and within California.

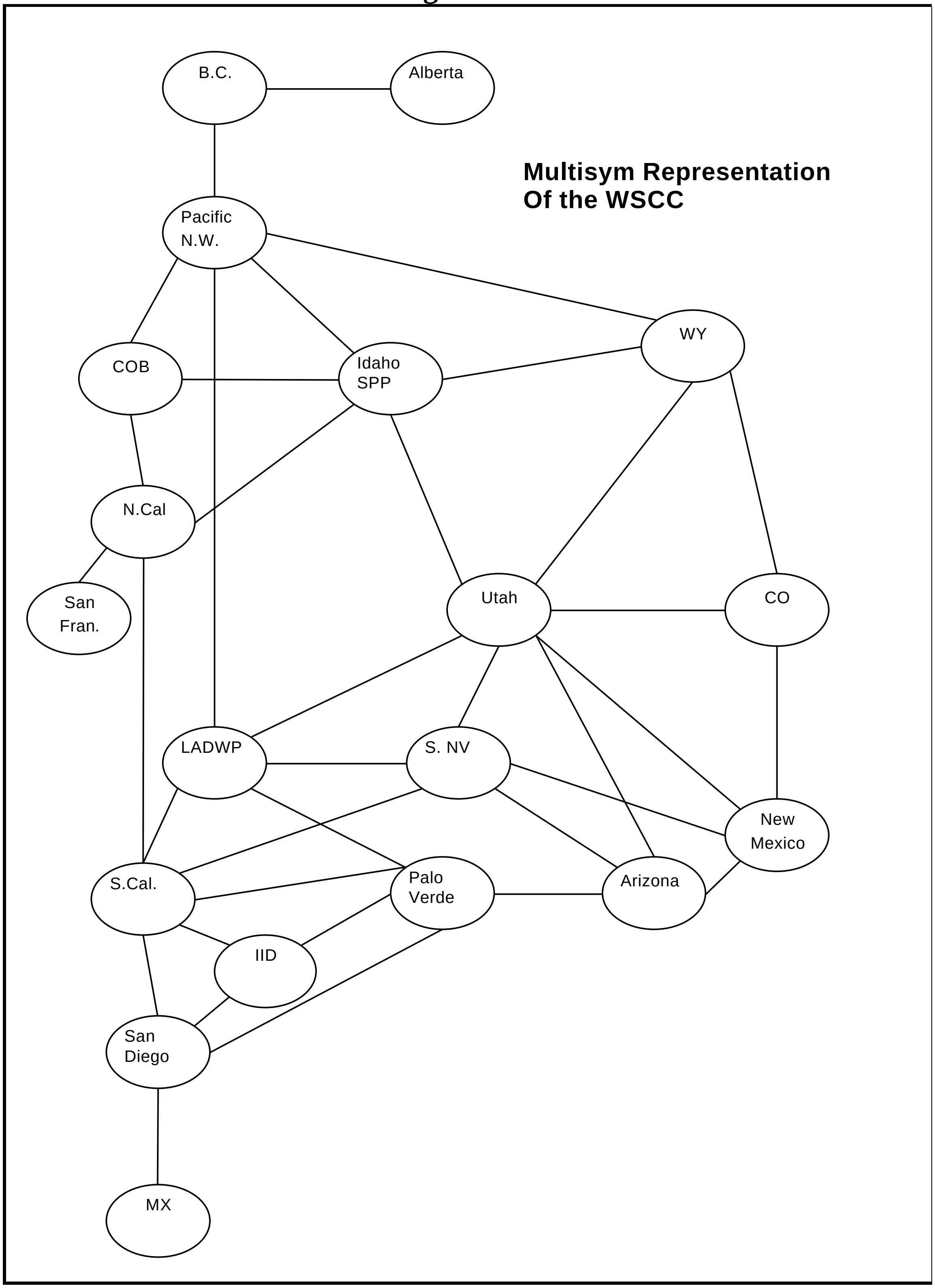
The loads and resources associated with the PG&E service area are divided among three of the transmission areas shown in Figure II-4. The PG&E service area loads and resources within the San Francisco Peninsula are in a separate transmission area. Those PG&E service area loads and resources that are located south of Path 15 are included in the Southern California transmission area along with all the Southern California Edison loads and resources. All other PG&E service area loads and resources are located in the Northern California transmission area along with the loads and resources of all the Northern California municipal utilities.

Table II-2
Transmission Capacity Between Transmission Areas

From	To	MW	MW Back
Arizona	New Mexico	3,409	3,485
Arizona	Palo Verde	9,999	9,999
ID-SPP	COB	300	300
No California	COB	3,675	4,600
No California	CSF	700	700
No California	So California	2,800	3,265
Northwest	COB	14,799	13,704
Northwest	LADWP	2,971	3,100
Palo Verde	IID	163	163
Palo Verde	LADWP	468	468
San Diego	IID	150	150
San Diego	Mexico	408	408
San Diego	Palo Verde	1,168	1,168
San Diego	So California	1,800	1,800
So California	IID	600	600
So California	LADWP	3,700	3,700
So California	Palo Verde	1,082	1,082
So California	So Nevada	2,814	2,814
So Nevada	Arizona	3,552	3,552
So Nevada	LADWP	3,823	3,823
So Nevada	New Mexico	985	985
So Nevada	UTAH	300	275
UTAH	Arizona	190	250
UTAH	LADWP	1,920	1,400

Source: Energy Commission staff.

Figure II-4



Source: Energy Commission staff.

Local Reliability Constraints

Within California, local reliability constraints determine the amount of an area's load that must be met by local generation. The San Francisco transmission area has a local reliability requirement that is enforced in the model by requiring that approximately 50 percent of the area's peak demand be met with local generation. Part of meeting this requirement involves designating the Hunters Point 4 and Potrero 3 units as must-run. During low load hours, they run at their minimum level (96 MW in total).

Local reliability requirements are also enforced in the Northern California and San Diego transmission areas. In Northern California, we specified that at least one of the two Humboldt units must be running at all times. If one unit is forced out or on maintenance, the other is turned on. We implemented a similar must-run requirement for the Encina 3 and 4 units in the San Diego transmission area. The South Bay 1 unit in San Diego is also designated as must-run. Additionally, for the San Diego area, we imposed the requirement that all but 2,250MW of demand must be met by generation within the San Diego area. This local generation requirement was imposed to satisfy the ISO operational requirement that limits simultaneous transfers into San Diego from Palo Verde and the Southern California transmission area.

We also imposed a local generation requirement for the Mexico transmission area. All but 340 MW[19] of demand in the Mexico area must be met with local generation. In addition, several units in the Mexico area were designated as must-run to better mimic the data that we had for actual flows of electricity over WSCC Path 45 (the link between the San Diego and Mexico transmission areas). The units in Mexico modeled as must-run include all of the geothermal facilities at Cerro Prieto and the six PDTE Juarez steam turbines (with an aggregate minimum operating level of 575 MW and 293 MWs respectively).

Unit Outages

For most units, forced outages were characterized with an equivalent forced outage rate. For some units, partial availability rates, by capacity block level, were used. Unit maintenance was specified using an equivalent maintenance outage rate. Nuclear units were not allowed to be forced out due to the sensitivity of the simulation results to their outages. The maintenance for the nuclear units was prescheduled to coincide with their refueling schedules; they were operating throughout the simulation period of this study.

For non-nuclear units, the probability of a maintenance outage occurring during the summer peak period was determined by a monthly maintenance factor, which distributes maintenance outages throughout the year. The maintenance factors used in Multisym™ were based on historical monthly planned and unplanned maintenance data submitted by the WSCC to the EIA (Form 411, *Coordinated Bulk Power Supply Program Report*).

[19] The 340 MW value was reported in the NERC 1998 Electricity Supply & Demand database as the summer capacity purchase by Mexico for 1999.

The monthly maintenance factors vary by transmission area. For the summer peak demand months, the probability of a unit being taken out for maintenance is less than for the low load months. For our one-week analysis of the summer peak, the probability that a unit was out for maintenance, in any of the California transmission areas, was less than 1 percent. Forced outages, however, have an equal probability of occurring throughout the year and were no more or less likely to occur during the summer peak demand week under study than at any other time during the year.

Unit outages are the result of a random drawn in each run of the model. The Multisym™ model uses a convergent Monte Carlo method for distributing both forced and unscheduled maintenance outages. This method rejects improbable outage distributions and provides results within one or two percent of a standard Monte Carlo approach after one or two iterations. It, therefore, is relatively fast compared to using a conventional Monte Carlo approach, which may require one hundred or more iterations.

Operating Reserve Requirements

Operating reserves ensure that there is adequate generation available to respond to sudden changes in load, generation and transmission failures, and system separations. Operating reserves are the sum of spinning reserves and non-spinning reserves. Spinning reserves are provided by the unloaded capacity of generating units that are connected to the system and have the ability to respond within ten minutes to changes in demand. Spinning reserves are comprised of a regulation reserve, which consists of generation under automatic generation control and contingency reserve. Non-spinning reserves consist of generating units, primarily combustion turbines that are not operating, but can provide power within ten minutes. Interruptible load that can be curtailed in ten minutes can also count towards non-spinning reserve.

Within Multisym™, operating reserves can be specified at the transmission area level, at the control area level (a control area consists of one or more transmission areas), and at the system level (the entire WSCC). For our evaluation of supply adequacy, we applied an operating reserve requirement for the entire WSCC of 7 percent with a spinning reserve requirement of 3 1/2 percent. For the California ISO control area we specified an operating reserve requirement of seven percent and a spinning reserve requirement equal to 4 1/2 percent[20]. For transmission areas within the WSCC that have a high percentage of generation from hydro facilities, a lower operating reserve requirement was used, in keeping with WSCC Minimum Operating Reliability Criteria (MORC)[21]. Operating reserves of 5 and 6 percent were applied, respectively, to the British Columbia and Pacific Northwest transmission areas.

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[20] The ISO has historically procured spinning reserves in excess of 4 ½ percent. The ISO's regulation (up) requirements range from 2-8 percent over a day; contingency reserves averaged 2.7 percent for the year ending 3/31/99.

[21] These criteria specify maintenance of operating reserves equal to 5 percent of load served by hydro generation, 7 percent of load served by thermal facilities.

Study Results

Tables II-3 through **II-5** summarize the results of the Multisym™ simulations for our base case and two hot weather scenarios. These tables provide a snapshot of loads and available resources for the entire WSCC system at the hour of California coincident peak demand. In all three of the scenarios, there was no unserved energy. However, the ability of the system to reliably meet demand, as measured in terms of available reserves, varied significantly among the different cases.

In **Tables II-3** through **II-5**, the far right-hand columns give the available margin of capacity over total loads in terms of MWs and percent. In the base case, the generation capacity in the California ISO control area[22] and the California-Mexico WSCC region was sufficient to meet peak demand, including the loads of interruptible customers and provide a 7 percent reserve margin. The Desert Southwest region has only a 5 percent reserve margin at the time of the peak demand. In the Northwest and Rocky Mountain regions, capacity reserves are well into the double-digit range. The ability of these regions to provide reserve support to other regions of the WSCC is a function of both available transmission capacity and water conditions. In our analysis, we have assumed average/moderate hydro conditions throughout the WSCC. Most of the excess capacity available in the Northwest region is energy-limited in that it depends on how much water is behind the dam to make that capacity available.

Table II-4 shows the results for our 1-in-5 year temperature scenario. The reserve margin on peak for California falls to 4 percent. Reserve margins for the rest of the WSCC remain relatively unchanged. This is due to the fact that when 1-in-5 year temperature conditions occur in California, the rest of the WSCC is not substantially hotter than normal. However, when 1-in-40 year temperatures prevail in California, the remainder of the WSCC is extremely hot as well.

The results of the 1-in-40 scenario are shown in **Table II-5**. To meet demand in California, a substantial share, 81 percent, of the interruptible load in the California ISO control area is called on. Our estimate of demand corresponding to the 1-in-40 year scenario may be somewhat conservative because the demand for the San Diego/Mexico transmission area is assumed the same as in the 1-in-5 scenario. This assumption was necessary because historical temperature data corresponding to the 1-in-40 scenario were not available for the San Diego area.

In the Desert Southwest region, reserve margins fall to 2 percent in the 1-in-40 scenario, while the Northwest Power Pool area remains relatively unchanged and reserves in the Rocky Mountain region decline in response to increased exports, but are still in the double-digit range.

[22] SMUD and the other northern California municipal utility loads and resources are included under the ISO control area. They not members of the California ISO. However, our inclusion of their loads and resources in the ISO control area is consistent with the ISO's treatment of northern California munis in their *1999 Summer Operations Plan* and allows us to compare our estimated reserve levels for the summer of 1999 to those of the ISOs.

The two factors in our modeling of the WSCC system that represent the biggest source of uncertainty with respect to the ability to reliably meet peak demand are hydro availability, which was discussed above, and generation outages. The model's random draw approach to unit outages—both maintenance and forced outages—yields total outages for each hour (i.e., total MW of generation capacity forced out) that fluctuate around an expected value based on the unit's historical outage rate. The modeling of generation outages in the three demand scenarios was held constant. The results for each scenario in **Tables II-3** through **II-5** show the same amount of capacity unavailable at the time of the California coincident peak.

For the California ISO control area, 2,752 MW of generation are unavailable in each scenario. This is significantly higher than the 1,500 MW of capacity that the California ISO assumed would be unavailable at the time of system peak demand in their ***1999 Summer Operations Plan.*** The outages generated by the model may be viewed as conservative, however, given that the nuclear units in the WSCC were not allowed to be forced out by the model.

Table II-3
Base Case Results Coincident Peak for California

Transmission Area	Peak Demand + Sales	Interruptible Load Available	Installed Generation	Firm Transactions	Total Unavailable Generation	Interruptible Load Called	Net Imports	Net Generation + Net Imports	Margin Over Loads (MW)	Margin Over Loads (%)
California ISO - North of Path 15	20,181	470	18,723	1,559	915	0	2,074	21,441	1,260	6%
California ISO - South of Path 15	21,191	2,270	22,223	1,318	1,472	0	993	23,062	1,871	9%
California ISO - San Diego Gas & Electric	3,334	40	2,123	240	365	0	1,336	3,334	0	0%
California ISO - San Francisco	878	0	787	0	0	0	91	878	0	0%
Total California ISO	45,584	2,780	43,856	3,117	2,752	0	4,494	48,715	3,131	7%
Imperial Irrigation District	644	0	1,437	214	136	0	-748	766	122	19%
Los Angeles Department of Water & Power	6,176	270	5,374	517	424	0	1,105	6,573	397	6%
Total California	52,404	3,050	50,667	3,848	3,311	0	4,851	56,054	3,650	7%
Comision Federal de Electricidad	1,535	0	1,540	0	62	0	182	1,660	125	8%
Total California-Mexico	**53,939**	**3,050**	**52,207**	**3,848**	**3,373**	**0**	**5,033**	**57,714**	**3,775**	**7%**
Arizona	11,424	506	13,244	570	852	0	-1,389	11,572	148	1%
New Mexico	3,012	0	5,233	-172	745	0	-1,052	3,264	252	8%
Southern Nevada	4,582	169	5,993	-712	43	0	-129	5,110	528	12%
Total Arizona-New Mexico S.Nevada	**19,018**	**675**	**24,470**	**-314**	**1,640**	**0**	**-2,570**	**19,946**	**928**	**5%**
Alberta	6,648	300	8,063	-125	685	0	-168	7,085	437	7%
British Columbia Hydro and Power Authority	6,751	0	11,329	261	0	0	-399	11,191	4,440	66%
Idaho/Sierra Pacific Power	4,546	0	4,065	62	201	0	1,739	5,665	1,119	25%
Northwest (Oregon/Washington/Montana)	23,735	0	40,859	-2,973	292	0	95	37,690	13,955	59%
Utah	4,091	171	5,633	-666	12	0	-425	4,530	439	11%
Total Northwest Power Pool Area	**45,771**	**471**	**69,949**	**-3,441**	**1,190**	**0**	**842**	**66,161**	**20,390**	**45%**
Colorado	6,116	0	8,252	269	389	0	-842	7,291	1,175	19%
Wyoming	1,708	0	5,009	0	203	0	-2,464	2,342	634	37%
Total Rocky Mtn Power Power Area	**7,824**	**0**	**13,261**	**269**	**592**	**0**	**-3,306**	**9,633**	**1,809**	**23%**
Total WSCC	**126,552**	**3,797**	**159,888**	**362**	**6,795**	**0**	**0**	**153,455**	**26,903**	**21%**

Table II-4
Cal Hot 5 Results Coincident Peak for California

Transmission Area	Peak Demand + Sales	Interruptible Load Available	Installed Generation	Firm Transactions	Total Unavailable Generation	Interruptible Load Called	Net Imports	Net Generation + Net Imports	Margin Over Loads (MW)	Margin Over Loads (%)
California ISO - North of Path 15	20,938	470	18,723	1,559	915	0	2,031	21,398	460	2%
California ISO - South of Path 15	21,900	2,270	22,223	1,318	1,472	0	1,404	23,473	1,573	7%
California ISO - San Diego Gas & Electric	3,399	40	2,123	240	365	0	1,401	3,399	0	0%
California ISO - San Francisco	878	0	787	0	0	0	91	878	0	0%
Total California ISO	47,115	2,780	43,856	3,117	2,752	0	4,927	49,148	2,033	4%
Imperial Irrigation District	654	0	1,437	214	136	0	-858	656	2	0%
Los Angeles Department of Water & Power	6,479	270	5,374	517	424	0	1,021	6,488	9	0%
Total California	54,248	3,050	50,667	3,848	3,311	0	5,089	56,292	2,044	4%
Comision Federal de Electricidad	1,552	0	1,540	0	62	0	199	1,677	125	8%
Total California-Mexico	**55,800**	**3,050**	**52,207**	**3,848**	**3,373**	**0**	**5,288**	**57,969**	**2,169**	**4%**
Arizona	11,311	506	13,244	570	852	0	-1,502	11,459	148	1%
New Mexico	2,989	0	5,233	-172	745	0	-1,175	3,141	152	5%
Southern Nevada	4,626	169	5,993	-712	43	0	-59	5,180	554	12%
Total Arizona-New Mexico S.Nevada	**18,926**	**675**	**24,470**	**-314**	**1,640**	**0**	**-2,736**	**19,780**	**854**	**5%**
Alberta	6,662	300	8,063	-125	685	0	-158	7,095	433	6%
British Columbia Hydro and Power Authority	6,741	0	11,329	261	0	0	-413	11,177	4,436	66%
Idaho/Sierra Pacific Power	4,640	0	4,065	62	201	0	1,817	5,743	1,103	24%
Northwest (Oregon/Washington/Montana)	23,685	0	40,859	-2,973	292	0	69	37,664	13,979	59%
Utah	4,118	171	5,633	-666	12	0	-398	4,557	439	11%
Total Northwest Power Pool Area	**45,846**	**471**	**69,949**	**-3,441**	**1,190**	**0**	**917**	**66,236**	**20,390**	**44%**
Colorado	6,127	0	8,252	269	389	0	-1,005	7,127	1,000	16%
Wyoming	1,727	0	5,009	0	203	0	-2,465	2,342	615	36%
Total Rocky Mtn Power Power Area	**7,854**	**0**	**13,261**	**269**	**592**	**0**	**-3,470**	**9,469**	**1,615**	**21%**
Total WSCC	**128,426**	**3,797**	**159,888**	**362**	**6,795**	**0**	**0**	**153,455**	**25,029**	**19%**

Table II-5
Cal Hot 40 Results Coincident Peak for California

Transmission Area	Peak Demand + Sales	Interruptible Load Available	Installed Generation	Firm Transactions	Total Unavailable Generation	Interruptible Load Called	Net Imports	Net Generation + Net Imports	Margin Over Loads (MW)	Margin Over Loads (%)
California ISO - North of Path 15	22,123	470	18,723	1,559	915	470	2,630	21,997	-126	-1%
California ISO - South of Path 15	23,074	2,270	22,223	1,318	1,472	1,739	1,472	23,541	467	2%
California ISO - San Diego Gas & Electric	3,399	40	2,123	240	365	40	1,205	3,203	-196	-6%
California ISO - San Francisco	878	0	787	0	0	0	91	878	0	0%
Total California ISO	49,474	2,780	43,856	3,117	2,752	2,249	5,398	49,619	145	0%
Imperial Irrigation District	669	0	1,437	214	136	0	-843	671	2	0%
Los Angeles Department of Water & Power	6,598	270	5,374	517	424	0	1,140	6,607	9	0%
Total California	56,741	3,050	50,667	3,848	3,311	2,249	5,694	56,898	157	0%
Comision Federal de Electricidad	1,539	0	1,540	0	62	0	61	1,539	0	0%
Total California-Mexico	**58,280**	**3,050**	**52,207**	**3,848**	**3,373**	**2,249**	**5,755**	**58,437**	**157**	**0%**
Arizona	11,716	506	13,244	570	852	0	-1,465	11,496	-220	-2%
New Mexico	3,038	0	5,233	-172	745	0	-1,126	3,190	152	5%
Southern Nevada	4,741	169	5,993	-712	43	0	-20	5,219	478	10%
Total Arizona-New Mexico S.Nevada	**19,495**	**675**	**24,470**	**-314**	**1,640**	**0**	**-2,611**	**19,905**	**410**	**2%**
Alberta	6,687	300	8,063	-125	685	0	-173	7,080	393	6%
British Columbia Hydro and Power Authority	6,772	0	11,329	261	0	0	-447	11,143	4,371	65%
Idaho/Sierra Pacific Power	4,637	0	4,065	62	201	0	1,757	5,683	1,046	23%
Northwest (Oregon/Washington/Montana)	23,957	0	40,859	-2,973	292	0	140	37,735	13,778	58%
Utah	4,091	171	5,633	-666	12	0	-472	4,483	392	10%
Total Northwest Power Pool Area	**46,144**	**471**	**69,949**	**-3,441**	**1,190**	**0**	**805**	**66,124**	**19,980**	**43%**
Colorado	5,991	0	8,252	269	389	0	-1,394	6,738	747	12%
Wyoming	1,724	0	5,009	0	203	0	-2,556	2,251	527	31%
Total Rocky Mtn Power Power Area	**7,715**	**0**	**13,261**	**269**	**592**	**0**	**-3,950**	**8,989**	**1,274**	**17%**
Total WSCC	**131,634**	**3,797**	**159,888**	**362**	**6,795**	**2,249**	**0**	**153,455**	**21,821**	**17%**

California Independent System Operator Reserve Requirements

Tables II-6 and **II-7** provide a more complete assessment of system reliability for the California ISO control area. They take into account the frequency and magnitude of violations of the Cal ISO operating reserve requirements for the two hot weather scenarios during the week in which the California coincident peak demand occurs. In each table, the column labeled “firm import requirement” is a function of the ISO control area load, available (and unavailable) generation within the control area, and the reserve requirement. The tables also provide an accounting of available imports and the import deficit. Also provided are the operating reserve margins during the hour, which indicate whether reserve levels warrant a Stage II alert, (i.e., less than 5 percent). The amount of interruptible load available for curtailment by the ISO under Stage II conditions is shown in the last column.

In the base case, the model results show that operating reserves are sufficient in all hours to maintain a 7 percent operating reserve margin. In the 1-in-5 scenario, operating reserves fall below 7 percent in 5 hours and in 1 hour fall below 5 percent, the point at which interruptible load is curtailed.

In the 1-in-40 scenario, operating reserve violations occur during twelve hours. In 8 of these hours, the shortfalls are of sufficient magnitude to necessitate curtailing interruptible load. In each of these hours, there is enough interruptible load available to restore a 5 percent operating reserve margin.

Table II-6
1-in-5 Results
Cal ISO Operating Reserve Requirements (MW)

Hour	ISO Area Load	ISO Control Area Generation	Generation Outage	Available Generation	Generation Serving Load	Operating Reserve Req	Resource Req.	Firm Import Req.	Available Imports[1]	Import Surplus/ Deficit	Operating Reserve (%)	Interruptible Load Available
87	46,678	43,856	2,775	41,081	38,394	2,688	49,366	8,284	7,783	(501)	5.69	2,780
88	47,115	43,856	2,752	41,104	38,415	2,689	49,804	8,700	8,044	(656)	5.29	2,780
111	45,742	43,856	3,571	40,285	37,650	2,635	48,377	8,092	7,569	(523)	5.61	2,780
112	46,251	43,856	3,891	39,965	37,351	2,615	48,866	8,900	8,118	(783)	4.90	2,780
113	44,971	43,856	3,814	40,042	37,423	2,620	47,591	7,548	7,289	(260)	6.31	2,780

[1] Includes 3,117 MW of firm transactions

Table II-7
1-in-40 Results
Cal ISO Operating Reserve Requirements

Hour	ISO Area Load	ISO Control Area Generation	Generation Outage	Available Generatio n	Generation Serving Load	Operating Reserve Req.	Resource Req.	Firm Import Req.	Available Imports[1]	Import Surplus/ Deficit	Operating Reserve (%)	Interruptible Load Available
16	46,205	43,856	3,450	40,406	37,763	2,643	48,848	8,442	7,915	(528)	5.60	2,780
17	45,220	43,856	3,787	40,069	37,448	2,621	47,841	7,772	7,659	(113)	6.70	2,780
63	47,601	43,856	3,467	40,389	37,747	2,642	50,243	9,854	8,745	(1,109)	4.06	2,780
64	48,215	43,856	3,325	40,531	37,880	2,652	50,867	10,335	8,928	(1,408)	3.28	2,780
65	47,758	43,856	3,276	40,580	37,925	2,655	50,413	9,833	8,984	(848)	4.76	2,780
86	47,059	43,856	2,549	41,307	38,605	2,702	49,761	8,454	8,431	(23)	6.94	2,780
87	49,012	43,856	2,775	41,081	38,394	2,688	51,700	10,618	8,236	(2,382)	0.79	2,780
88	49,474	43,856	2,752	41,104	38,415	2,689	52,163	11,059	8,515	(2,544)	0.38	2,780
89	48,555	43,856	2,999	40,857	38,184	2,673	51,228	10,371	8,709	(1,662)	2.65	2,780
111	47,057	43,856	3,571	40,285	37,650	2,635	49,692	9,407	8,244	(1,163)	3.91	2,780
112	47,588	43,856	3,891	39,965	37,351	2,615	50,203	10,237	7,765	(2,472)	0.38	2,780
113	46,279	43,856	3,814	40,042	37,423	2,620	48,899	8,856	8,350	(507)	5.65	2,780

[1] Includes 3,117 MW of firm transactions

Network Flows

Tables II-6 and **II-7** illustrated the extent to which California relies on firm imports to meet its loads. Hydro availability becomes a critical factor in determining the overall reliability during the summer peak demand season. As mentioned earlier, reserve levels in the Northwest may appear high, but capacity in the Northwest is energy-limited. The ability of the Northwest region to provide energy to California and the rest of the WSCC during the summer peak season is primarily a function of hydro availability. In **Table II-8**, we show the results of our base case and two hot weather scenarios in terms of how much energy flowed between transmission regions during the peak demand week. These flows allow us to identify which links California are most dependent on and what, if any, excess capacity exists on these lines.

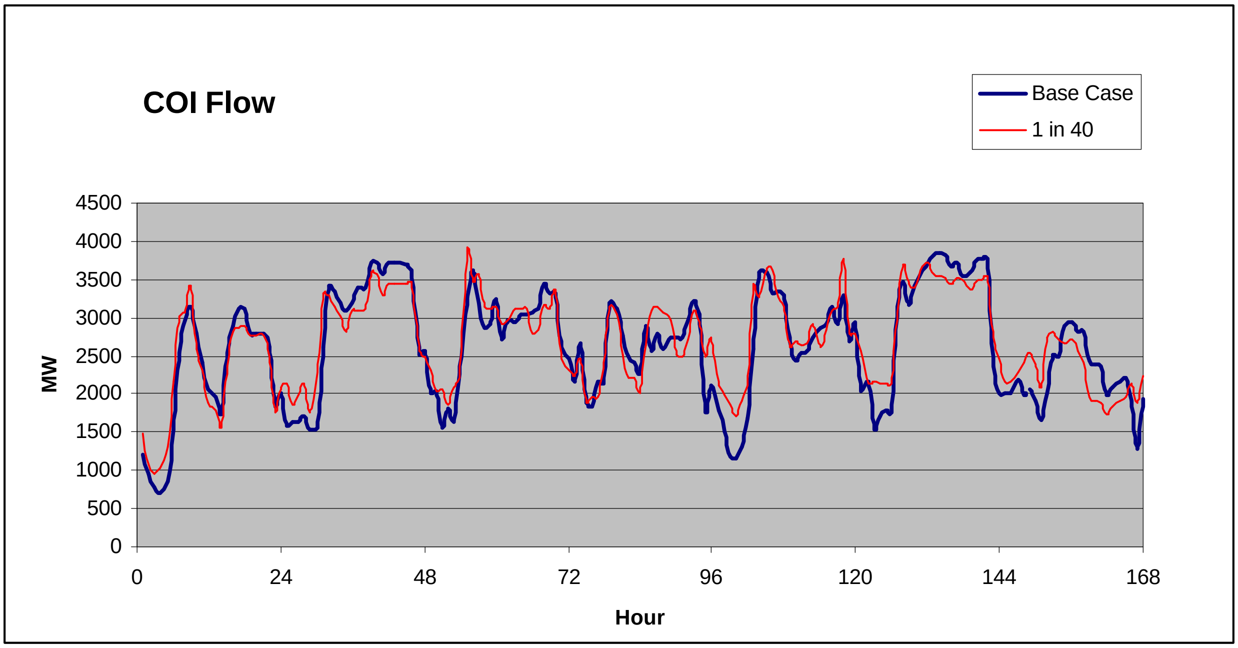
California Oregon Intertie/Pacific DC Intertie

In **Table II-8**, the two major transmission paths from the Northwest into California are represented by the California Oregon Border (COB) to Northern California path, which are the three 500kV AC lines that make up the California Oregon Intertie (COI), and the Northwest to LADWP path, which is the Pacific DC Intertie. The maximum summer rating used for these two paths in the North to South direction is 4,600 MW for COB to Northern California and 2,971 MW for Northwest to LADWP. (The ratings in both directions for all paths are given in **Table II-2**.) In all scenarios, these maximums are never reached. Flows on the COB-Northern California line top out at 3,875 MW in the 1-in-40 scenario. Flows on the DC line to LADWP reach a maximum of 1,508 MW in the 1-in-5 scenario. In our simulations, loading levels on the Pacific DC Intertie are lower than the levels that occurred last summer. These loading levels are a function of the Northwest hydro availability assumed in the study.[23]

The flows on the COI may be curtailed by 40 MW for every 100 MW that Northern California loads exceeds 23,400 MW. If loads are 24,400, then the COI limit is reduced to 4,200 MW. This threshold is not reached in any of the scenarios. Hourly flows for the base case and 1-in-40 scenario are illustrated below in **Figure II-5**.

[23] LADWP is also connected to Utah via the DC line from the Intermountain Power Project. This path has a capacity rating of 1,920 MW and is fully loaded for at least 39 hours of the week under all three scenarios.

Figure II-5
Beginning Monday 12AM Ending Sunday 11PM



Source: Energy Commission staff.

Table II-8
Network Flows

Transmission Path			Base Case			Cal Hot 5			Cal Hot 40		
Name	From	To	Energy GWh	MaxFlow MW	Hrs at Full Ld	Energy GWh	MaxFlow MW	Hrs at Full Ld	Energy GWh	MaxFlow MW	Hrs at Full Ld
Nor Cal to So Cal	Nor Cal	So Cal	0.1	31.4	0	0	31.4	0	0	0	0
	So Cal	Nor Cal	410.5	3265	27	407.3	3265	26	462.7	3265	62
Nor Cal to SF	Nor Cal	SF	51.7	530.9	0	37.7	492	0	33.7	446.2	0
	SF	Nor Cal	0.1	16	0	1.3	173	0	1.4	173	0
Nor Cal To COB	Nor Cal	COB	0	0	0	0	0	0	0	0	0
	COB	Nor Cal	438.2	3839.4	0	440	3796.5	0	448.2	3874.7	0
San Diego To So Cal	San Diego	So Cal	0	0	0	0.2	108.7	0	1.2	282.2	0
	So Cal	San Diego	87.4	1387.8	0	74.4	1325.8	0	52.5	1080.8	0
San Diego to Mexico	San Diego	Mexico	35	340	0	35.5	340	0	32.2	340	0
	Mexico	San Diego	0.1	33.4	0	0	21	0	0.2	79.2	0
San Diego To Palo V	San Diego	Palo Verde	0	0	0	0	0	0	0	0	0
	Palo Verde	San Diego	196.2	1168	167	196	1168	163	195.3	1168	159
So Cal To Palo V	So Cal	Palo Verde	0	0	0	0.1	86	0	0	0	0
	Palo Verde	So Cal	174.5	1082	155	177.7	1082	159	181.8	1082	168
So Cal To So Nev	So Cal	So Nevada	0	0	0	0	0	0	0	0	0
	So Nevada	So Cal	250.2	2814	14	267.5	2814	21	277.8	2814	21
So Cal To LADWP	So Cal	LADWP	0	0	0	0	0	0	0	0	0
	LADWP	So Cal	204	2294.7	0	210.8	2748.6	0	231.1	2733.9	0
Palo V To LADWP	Palo Verde	LADWP	58.3	468	107	64.6	468	122	61.5	468	115
	LADWP	Palo Verde	0	0	0	0	0	0	0	0	0
So Nevada To LADWP	So Nevada	LADWP	45.2	1263.7	0	44.8	1267.5	0	32.4	1154.7	0
	LADWP	So Nevada	0	0	0	0	0	0	0	0	0
Utah To LADWP	Utah	LADWP	208.2	1920	40	215.9	1920	39	231.2	1920	40
	LADWP	Utah	0	0	0	0	0	0	0	0	0
Northw To LADWP	Northwest	LADWP	131.8	1498.8	0	131.8	1508.3	0	131.3	1177.2	0
	LADWP	Northwest	0	0	0	0	0	0	0	0	0
Palo Verde To IID	Palo Verde	IID	21.2	163	14	21.5	163	21	20.6	163	18
	IID	Palo Verde	0	0	0	0	0	0	0	0	0
San Diego To IID	San Diego	IID	0	0	0	0	0	0	0	0	0
	IID	San Diego	24.5	150	153	24	150	148	23.1	150	134
So Cal To IID	So Cal	IID	0.2	64.1	0	0.1	64.1	0	0	13.6	0
	IID	So Cal	71.7	600	10	77.2	600	14	84.8	600	46
BC Hydro To Northw	BC Hydro	Northwest	128.1	1138.2	0	132.4	1142.2	0	136.1	1132.2	0
	Northwest	BC Hydro	0	0	0	0	0	0	0	0	0

Table II-8 (continued)
Network Flows

Transmission Path			Base Case			Cal Hot 5			Cal Hot 40		
			Energy	MaxFlow	Hrs at	Energy	MaxFlow	Hrs at	Energy	MaxFlow	Hrs at
Name	From	To	GWh	MW	Full Ld	GWh	MW	Full Ld	GWh	MW	Full Ld
BC Hydro To Alberta	BC Hydro	Alberta	0	0	0	0	0	0	0	0	0
	Alberta	BC Hydro	133.8	1000	57	133.4	1000	57	134.2	1000	64
Northw To ID-SPP	Northwest	ID-SPP	7.8	68.9	0	8	68.9	0	7.4	68.9	0
	ID-SPP	Northwest	8.1	702.7	0	6.8	601.2	0	11.2	1002.5	0
Northw To Wyoming	Northwest	Wyoming	0	0	0	0	0	0	0	0	0
	Wyoming	Northwest	99.8	700	105	96.2	700	98	102.6	700	108
Northw To COB	Northwest	COB	419.5	3793.4	0	425	3796.5	0	425	3574.7	0
	COB	Northwest	0	0	0	0	0	0	0	0	0
So Nev To Utah	So Nevada	Utah	0	0	0	0	0	0	0	0	0
	Utah	So Nevada	38.1	275	111	37.5	275	110	39	275	119
So Nevada To Arizona	So Nevada	Arizona	5	239	0	5.2	239	0	5.5	239	0
	Arizona	So Nevada	55.4	1821.9	0	63.5	1772.5	0	59.5	1524.4	0
So Nevada To New Mex	So Nevada	New Mexico	0	0	0	0	0	0	0	0	0
	New Mexico	So Nevada	147.2	985	120	153.8	985	134	152.4	985	138
ID-SPP To Utah	ID-SPP	Utah	0.7	7	0	0.7	7	0	1.9	486.6	0
	Utah	ID-SPP	0.3	78.8	0	0.6	241.7	0	2.2	645	1
ID-SPP To Wyoming	ID-SPP	Wyoming	0	0	0	0	0	0	0	0	0
	Wyoming	ID-SPP	269.7	2390	4	273.2	2390	3	278.8	2390	6
ID-SPP To COB	ID-SPP	COB	18.7	300	34	15	300	33	23.2	300	56
	COB	ID-SPP	0	0	0	0	0	0	0	0	0
Utah To Arizona	Utah	Arizona	5.3	190	22	4	190	16	5.9	190	24
	Arizona	Utah	0	0	0	0	0	0	0	0	0
Utah To New Mexico	Utah	New Mexico	43.6	565.1	0	43.2	493.3	0	43.6	535.3	0
	New Mexico	Utah	0	0	0	0	0	0	0	0	0
Utah To Colorado	Utah	Colorado	0.7	68	0	0.9	68	0	0.6	68	0
	Colorado	Utah	37.5	550	29	41.5	550	35	55	550	56
Utah To Wyoming	Utah	Wyoming	0	0	0	0	0	0	0.1	104	0
	Wyoming	Utah	21.9	200	101	20.6	200	86	19.8	200	79
Arizona To New Mexico	Arizona	New Mexico	0	0	0	0	0	0	0	0	0
	New Mexico	Arizona	181.7	2221.7	0	183.5	2171.9	0	204.3	2889.9	0
Arizona To Palo Verde	Arizona	Palo Verde	0	0	0	0	0	0	0	0	0
	Palo Verde	Arizona	184.6	2176.1	0	175	2227.9	0	175.7	1547.7	0
New Mex To Colorado	New Mexico	Colorado	0	0	0	0	0	0	0	0	0
	Colorado	New Mexico	80.9	650	80	75.8	650	67	82.8	650	88
Colorado To Wyoming	Colorado	Wyoming	1.5	363.4	0	1.7	280.4	0	3.1	403.6	0
	Wyoming	Colorado	46.9	1204.1	0	44.5	898.9	0	37.6	613.9	0

West-of-the Colorado River

Southern California is connected to the Southwest region via paths from the Southern Nevada and Palo Verde transmission areas. The path from Southern Nevada into California corresponds to the transmission lines that makeup the northern portion of the West-of-the-Colorado-River (WOR) system. The paths from Palo Verde transmission area into California, along with the path connecting IID to Southern California Edison, represent the southern portion of the WOR system. **Table II-9** shows the paths representing the WOR system in Multisym™, provides the results from the model in terms of the flows on the WOR, and the number of hours these paths comprising the WOR are fully loaded during our peak week simulation.

In our modeling of the WOR system, the East-to-West rating for the northern portion is 6,637 MW. The path between Southern Nevada and LADWP corresponds to the WOR lines that terminate at the Victorville and Adelanto substations. For this path we use a rating of 3,823 MW, which represents the entitlements on the line of LADWP and Burbank, Glendale and Pasadena (BGP). Flows on this path reach a maximum of 1,267 MW in our 1-in-5 scenario, but are substantially below that at the time of the California coincident peak demand. The path from Southern Nevada to Southern California represents the WOR lines terminating at the Lugo and Mirage substations and has a rating of 2,814 MW. During the peak demand week, this path is fully loaded for 14 hours in the base case and 21 hours in the two scenarios. Flows on this line at the time of the peak demand under our two scenarios, however, are at nearly half the available capacity.

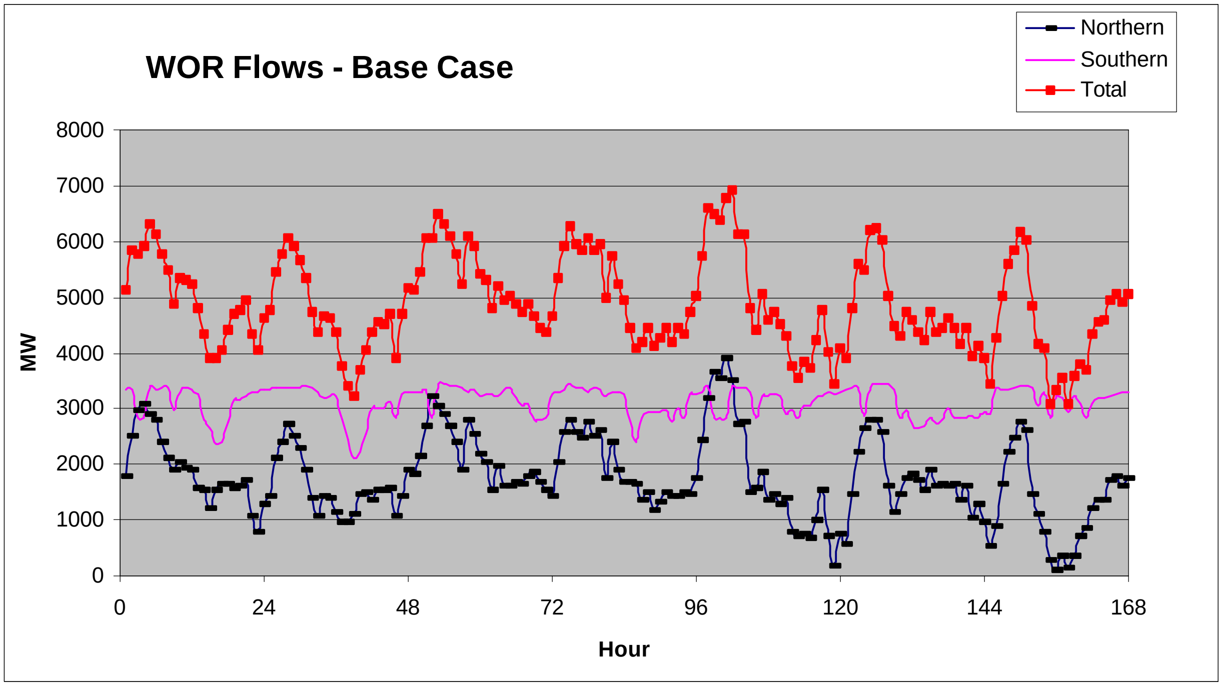
The lines from Palo Verde, comprising the southern portion of the WOR system, are the most heavily used in our modeling. They have a combined transfer capability of 3,481 MW. The paths to SCE and SDG&E are fully loaded for nearly all hours of the week under all three scenarios. The path to LADWP from Palo Verde is also fully loaded between 64 and 73 percent of the hours of the week in our three scenarios.

The results in **Table II-9** show that, with the exception of the IID–SCE path, the southern portion of the WOR System is heavily loaded during most hours. Flows on the northern system, on the other hand, are often light and well below the capacity limits of the lines. These flows are illustrated in **Figures II-6** through **II-8**. During the peak hours, the flows on the northern portion of the WOR drop off as demand in Southern Nevada limits the amount of energy available for export to California.

Table II-9
Representation of West-of-River in Multisym™

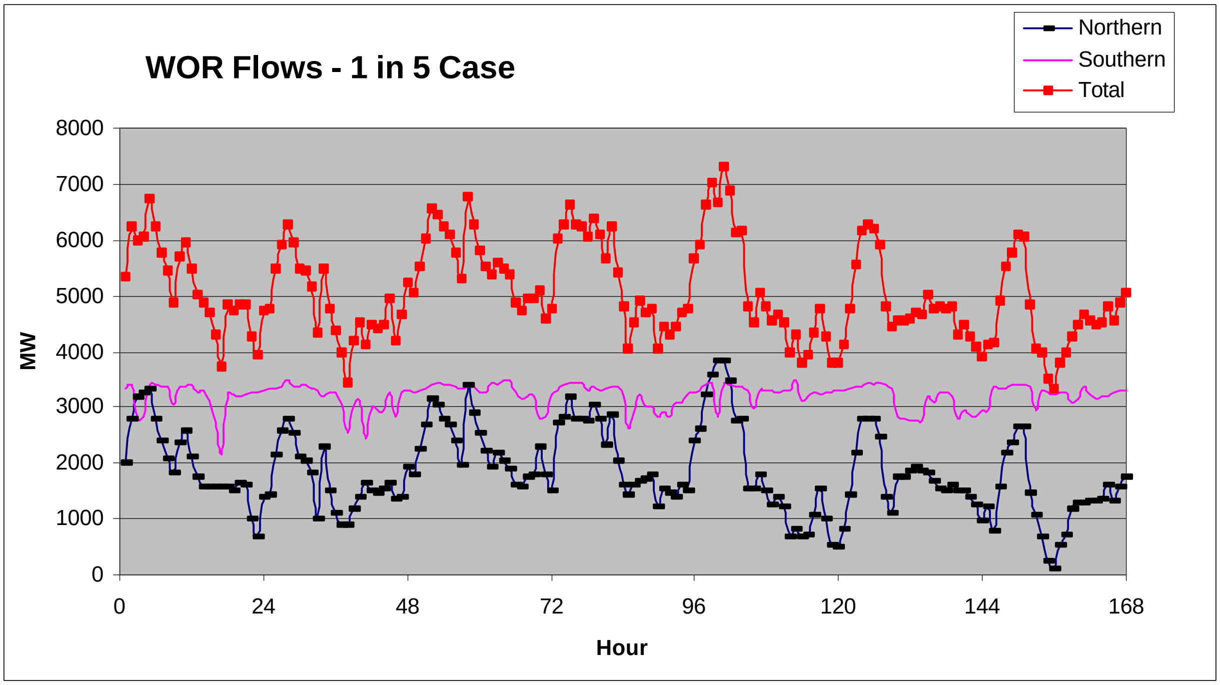
West of River	Rating (MW)	Base Case		1-in 5		1-in-40	
		Hours at Full Load	Flow at Peak (MW)	Hours at Full Load	Flow at Peak (MW)	Hours at full Load	Flow at Peak (MW)
Northern System							
So Nevada to So Cal	2,816	14	1025	21	1,495	21	1,343
So Nevada to LADWP	3,823	0	479	0	219	0	219
Southern System							
Palo Verde to So Cal	1,082	155	1082	129	1082	168	1,082
Palo Verde to San Diego	1,168	167	1168	163	1168	159	1,168
Palo Verde to LADWP	468	107	0	121	0	115	0
IID to Cal So	600	10	540	114	600	46	600
IID to San Diego	150	152	150	48	150	134	150

Figure II-6
West of River Flows – Base Case
Beginning Monday 12AM Ending Sunday 11PM



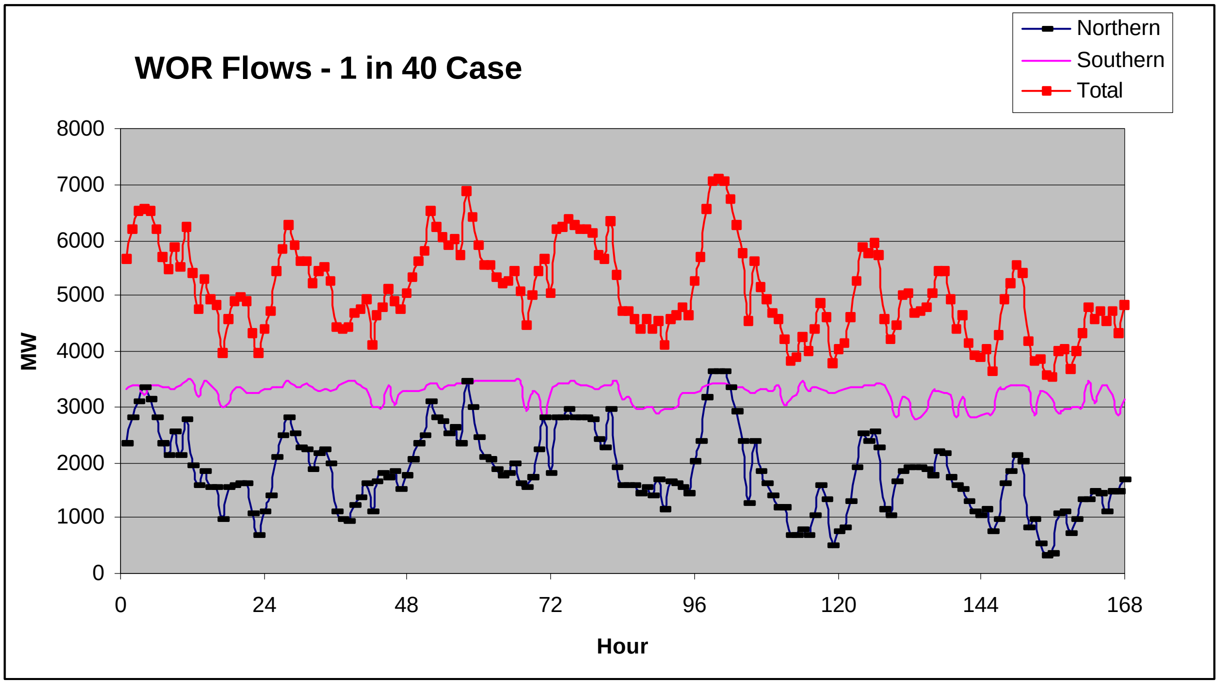
Source: Energy Commission staff.

Figure II-7
West of River Flows – 1-in-5 Case
Beginning Monday 12AM Ending Sunday 11PM



Source: Energy Commission staff.

Figure II-8
West of River Flows – 1-in-40 Case
Beginning Monday 12AM Ending Sunday 11PM



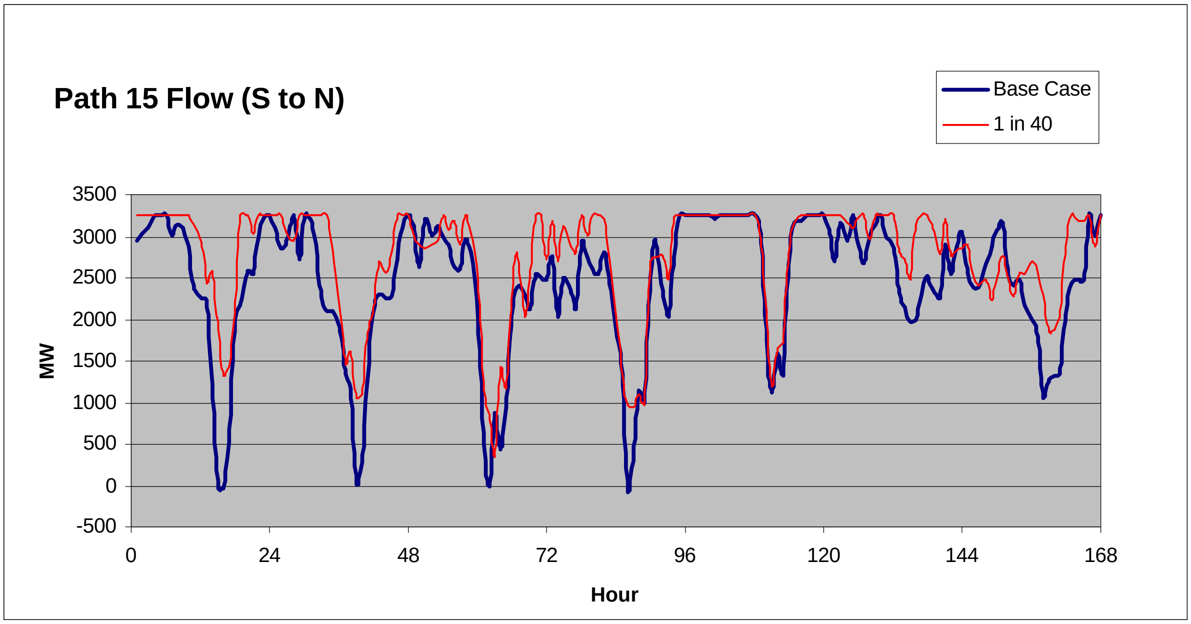
Source: Energy Commission staff.

Path 15

The path Nor Cal to So Cal in **Table II-8** represents the transfer capability between Northern California and Southern California. This path is identified in the WSCC path-rating catalogue as Path 15. Path 15 also defines the boundary between the two ISO transmission congestion zones.[24] In our one-week simulation, flows on this path are primarily in the south-to-north direction. The summer south-to-north rating for this path is 3,265 MW. With respect to the number of hours that this line is fully loaded; our modeling shows little difference between the base case and the 1-in-5 scenario, in which Path 15 is fully loaded 15 percent of the hours in the week. In our 1-in-40 scenario, however, the path is fully loaded 37 percent of the time. Hourly flows for the base case and 1-in-40 scenario are illustrated below in **Figure II-9**. During peak hours, south to north flows on Path 15 decrease in response to increased demand in Southern California. This decrease in flows into Northern California from the south is partially offset by an increase in north to south flows on the COI.

[24] The California ISO is considering creating a separate transmission congestion zone whose boundaries would be defined by Path 15 (Midway to Los Banos substations) on the northern end and Path 26 (Midway to Vincent substations) on the southern end. Historical hourly flow data for Path 26 shows flows during the summer peak hours in the North to South direction. See Figure II-13.

Figure II-9
Beginning Monday 12AM Ending Sunday 11PM



Source: Energy Commission staff.

Nomograms and Operating Constraints

The flows on most of the major paths into and within California are limited by operational procedures. These procedures are designed to ensure the reliability of the transmission network by preventing lines from overloading in response to various types of outages and demand levels. The limits imposed by these procedures are sometimes defined by a nomogram, which sets simultaneous flow limits on combinations of paths. Multisym™ cannot automatically limit the flow on one transmission path in response to changes in flows on other paths, which are governed by the same nomogram or in response to changes in demand. We did, however, try to determine if the transfer limits of the more critical nomograms affecting imports into California were being violated. If imports into the California ISO control area must be curtailed to satisfy the constraints imposed by a nomogram, this will have a direct effect on operating reserves within California ISO control area.

South of San Onofre Nuclear Generating Station

In Multisym™, the San Diego and Southern California transmission areas are linked via WSCC Path 44 (South of SONGS). The flow limits on this path are a function of the load levels in San Diego, imports into San Diego and the CFE Mexico portion of the WSCC. Simultaneous transfers into the San Diego transmission area are governed by a nomogram which limits total imports into San Diego and Mexico to 2,250 MW when San Diego load is below 3,400 MW and to 2,150 MW when San Diego load is above 3,600 MW. In our two extreme temperature scenarios, San Diego loads, at the time of the California coincident peak, are 3,399 MW[25].

[25] Because of incomplete temperature data for the SDG&E area, the peak demand for the SDG&E area for the 1-in-40 year scenario is identical to the peak demand for the 1-in-5 year scenario.

Table II-10 below shows that, at the time of the California coincident peak, imports into SDG&E and Mexico do not violate the 2,250 MW limit.

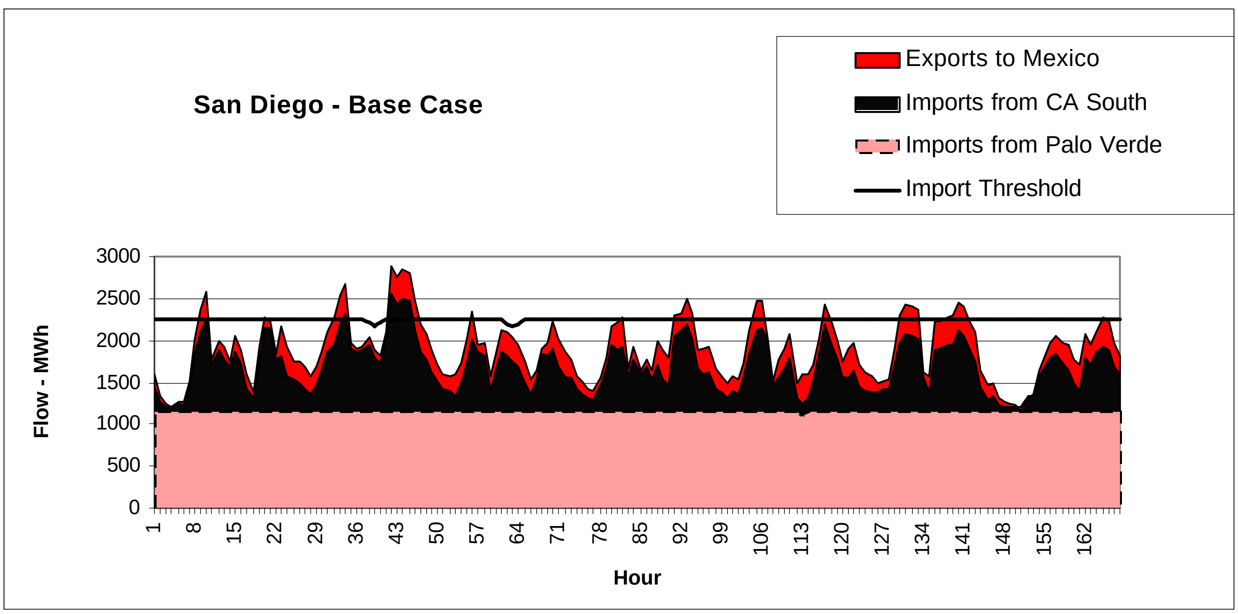
Table II-10
SDG&E/ Commision Federal de Electricidad, Mexico Imports

		Base Case		1-in-5		1-in-40	
Transmission Path	Max. Rating (MW)	Hours at Full Load	Load at Peak (MW)	Hours at Full Load	Load at Peak (MW)	Hours at Full Load	Load at Peak (MW)
CSCE to San Diego	1,800	0	541	0	485	0	276
Palo Verde to San Diego	1,168	167	1,168	163	1,168	159	1,168
San Diego to CFE	408	33[26]	283	32	162	27	149
Total (MW)	3,376		1,992		1,815		1,593

Source: Energy Commission staff.

While the nomogram constraint is satisfied during the coincident peak load hour, **Figures II-10** through **II-12** below show that the import constraint is violated in some off peak hours in all three scenarios. The violations, however, diminish as loads increase in San Diego and in neighboring transmission areas. Imports into San Diego are displaced by generation within the San Diego area, and less surplus electricity is available from SCE and the Southwest for import.

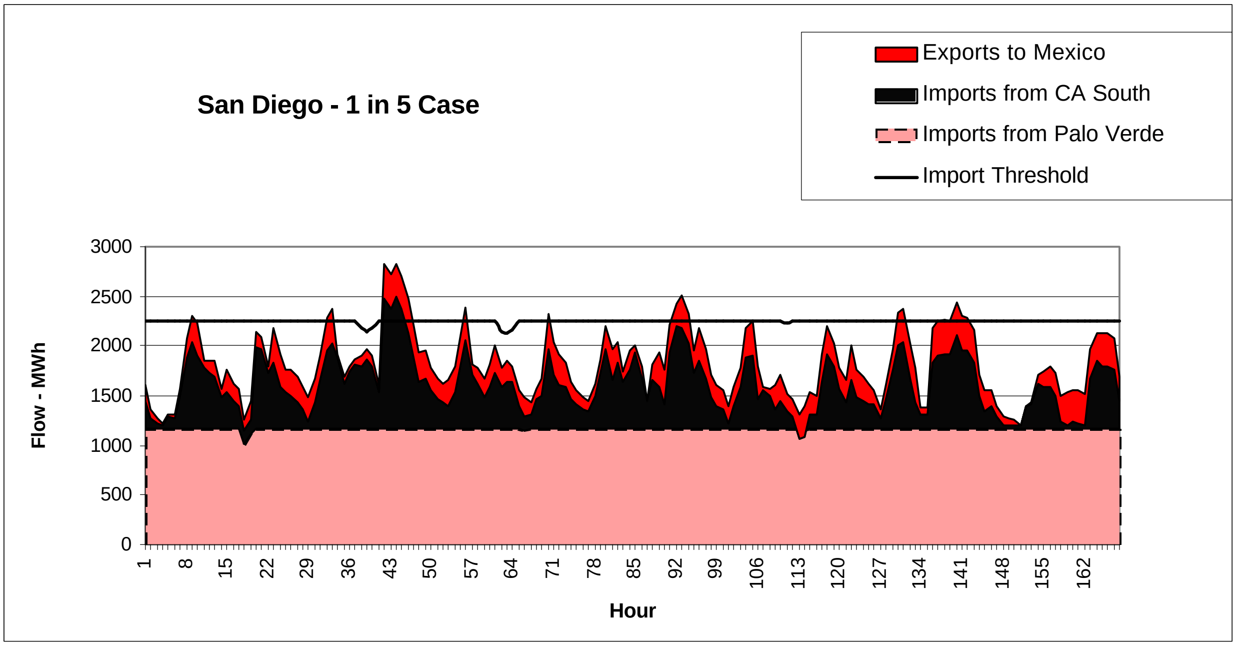
Figure II-10
San Diego/Commision Federal de Electricidad, Mexico Imports
Beginning Monday 12 AM Ending Sunday 11 PM



Source: Energy Commission staff.

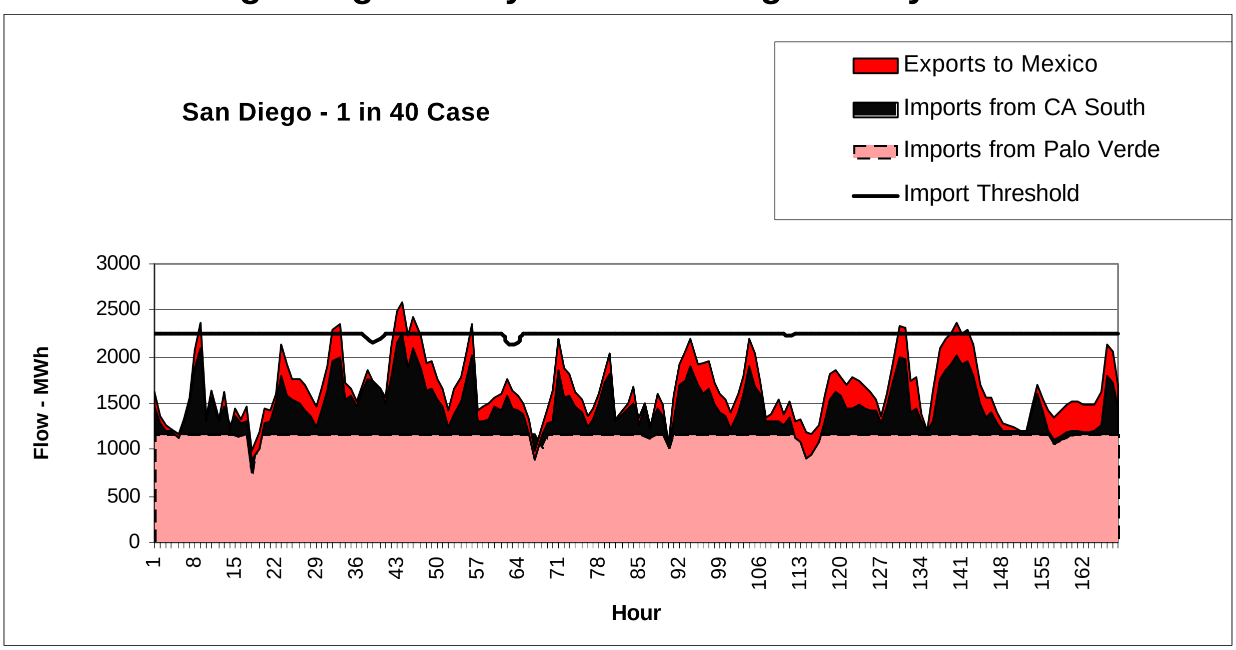
[26] Number of hours at 340 MW, the value to which imports are constrained; the rated capacity of the line is 408 MW.

Figure II-11
San Diego/Commision Federal de Electricidad, Mexico Imports
Beginning Monday 12 AM Ending Sunday 11 PM



Source: Energy Commission staff.

Figure II-12
San Diego/Commision Federal de Electricidad, Mexico Imports
Beginning Monday 12 AM Ending Sunday 11 PM



Source: Energy Commission staff.

East-of-River/Southern California Import Transmission

The EOR/SCIT nomogram monitors power flows on five major paths into Southern California, system inertia[27] in the Southern California area, and the flows on a set of transmission lines east of the Colorado River. The non-simultaneous rating on the EOR path is 7,550 MW and 18,886 MW on the SCIT. In Multisym™, the EOR consists of the paths in **Table II-11**.

Table II-11
East of River Transmission System

East of River	From	To	Rating E to W (MW)
(Northern System)	New Mexico	So Nevada	985
	Arizona	So Nevada	3,552
(Southern System)*	Palo Verde	IID	163
	Palo Verde	LADWP	1,168
	Palo Verde	CSCE	1,082
	Palo Verde	CSDGE	468
Total			7,418

The Southern portion of EOR excludes Arizona Public Service's entitlement of 132 MW

The SCIT is made up of the lines/paths shown in **Table II-12** below.

Table II-12
Southern California Import Transmission System

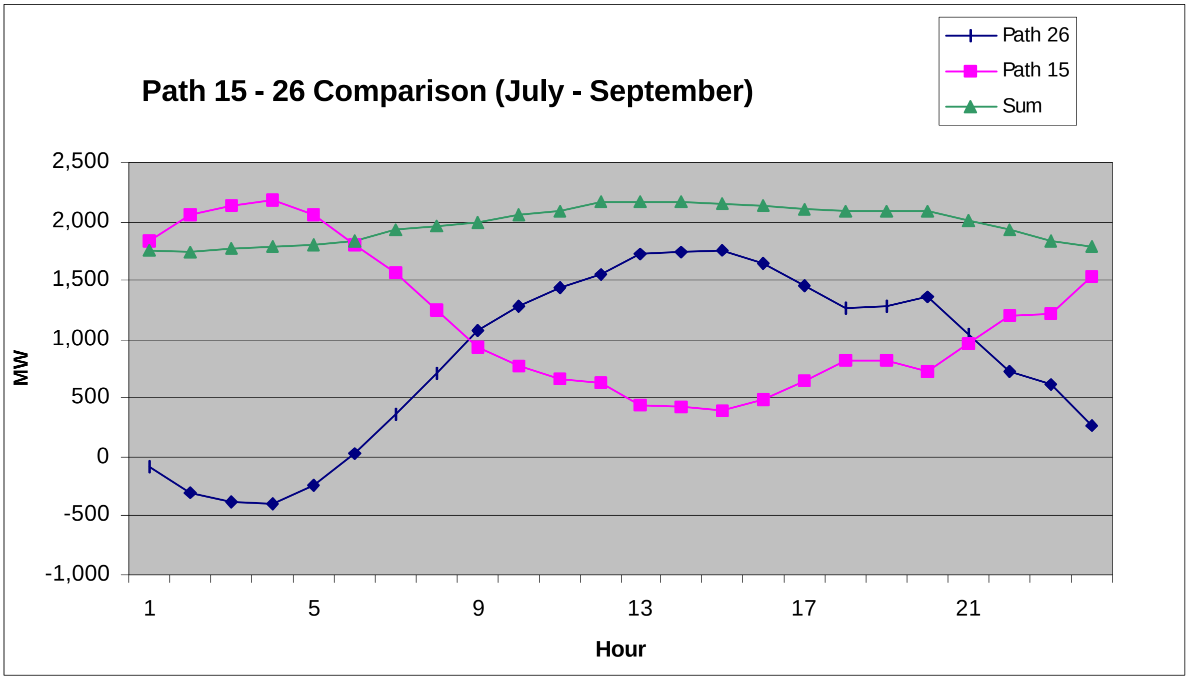
SCIT	MW
Midway Vincent	2,800
Pacific DC Intertie	2,971
IPP DC Line	1,920
North of SCE Lugo Path	1,200
West of River	10,118
Total	19,009

Source: Energy Commission staff.

The network topology used in this study does not contain an explicit representation of the Midway-Vincent or the North of SCE Lugo Paths. Flows on the Midway-Vincent line, also known as WSCC Path 26, however, can be imputed from flows on Path 15. **Figure II-13** illustrates the relationship between the two paths using historical flow data from the summer of 1998. We calculated flows over Path 26 as a function of the flows over Path 15. The sum of flows over Paths 15 and 26 during peak hours (13 to 21) is routinely between 2,000 and 2,200 MW.

[27] System inertia is important to maintaining the stability of a system. It is a function of the mass of the rotating parts of a turbine generator which stores energy that can be released to slow the rate of frequency decay following loss of generation or islanding.

Figure II-13
Comparison of Paths 15 and 26



Source: Energy Commission staff.

The ISO operating procedure for the 1999 summer limits flows on the SCIT to between 11,000 – 13,320 MW. A derate of 100 MW from 13,320 MW will occur for every 100 MW the SCE load is above 18,000 MW. If the SCE load is 19,000 MW, then the SCIT import limit is 12,320 MW. **Table II-13** sums the flows on the paths comprising the SCIT at the time of the California peak demand. While **Table II-13** does not include flows over the North of SCE Lugo Path, it does not appear that the SCIT nomogram will limit imports into Southern California.

Table II-13
Total Southern California Import Transmission System*

	Base	1-in-5	1-in-40
Path 26	1,345	1,278	1,372
Pac DC Intertie	1,177	1,177	1,177
IPP DC Line	1,073	1,324	1,411
WOR	4,438	4,714	4,562
Total Flows on Peak	8,033	8,493	8,522

* Does not include North of SCE Lugo Path Flows

Source: Energy Commission staff.

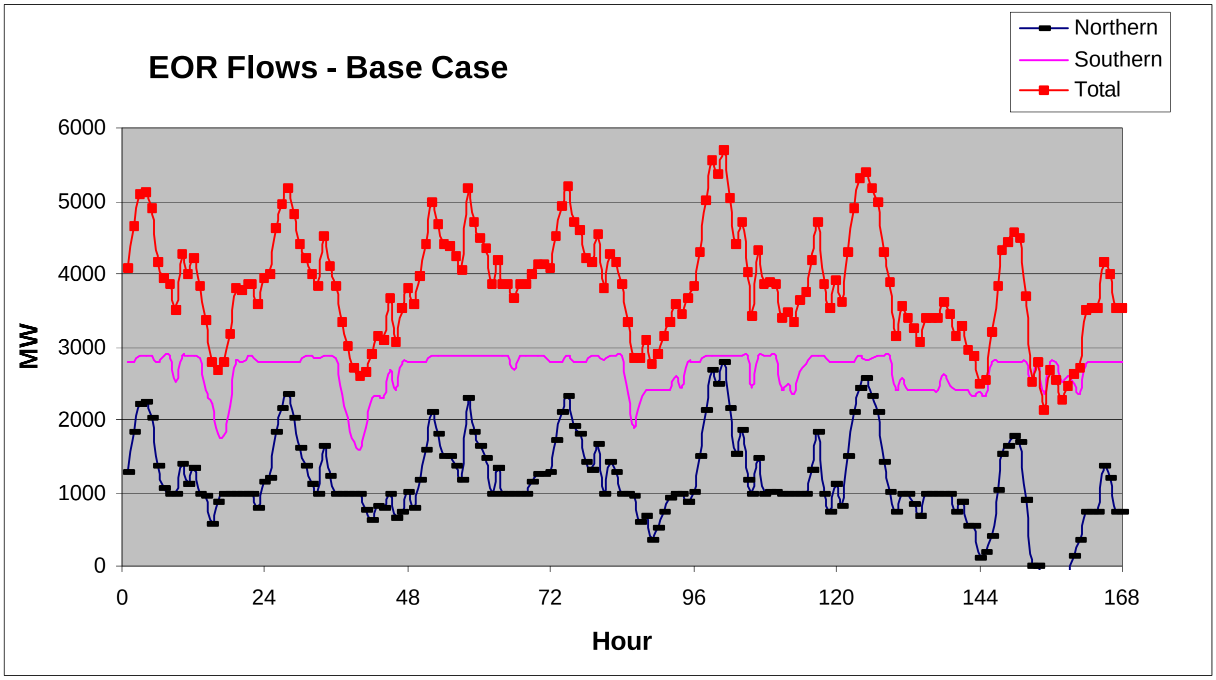
The EOR flows at the time of the California coincident peak are provided in **Table II-14**. **Figures II-14** through **II-16** illustrate the EOR flows for our three scenarios. The southern system of lines is often fully loaded, while flows on the northern system are significantly below the 4,537 MW carrying capacity. The flows on the northern system drop off during the peak demand hours to meet load in Arizona and New Mexico.

Table II-14
East of River Flows

Flow at Peak Hour	Base	1-in-5	1-in-40
Northern System	691	971	858
Southern System	2,400	2,356	2,371
EOR Total	3,191	3,327	3,229

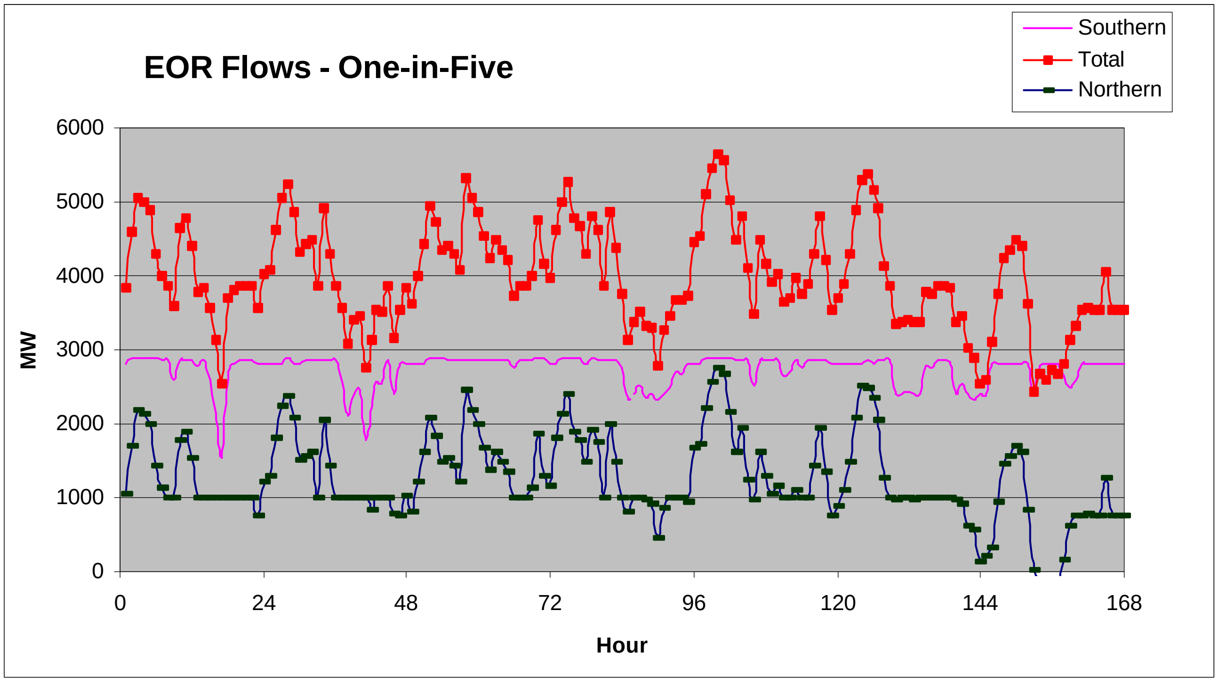
Source: Energy Commission staff

Figure II-14
East of River Flows
Beginning Monday 12 AM Ending Sunday 11 PM



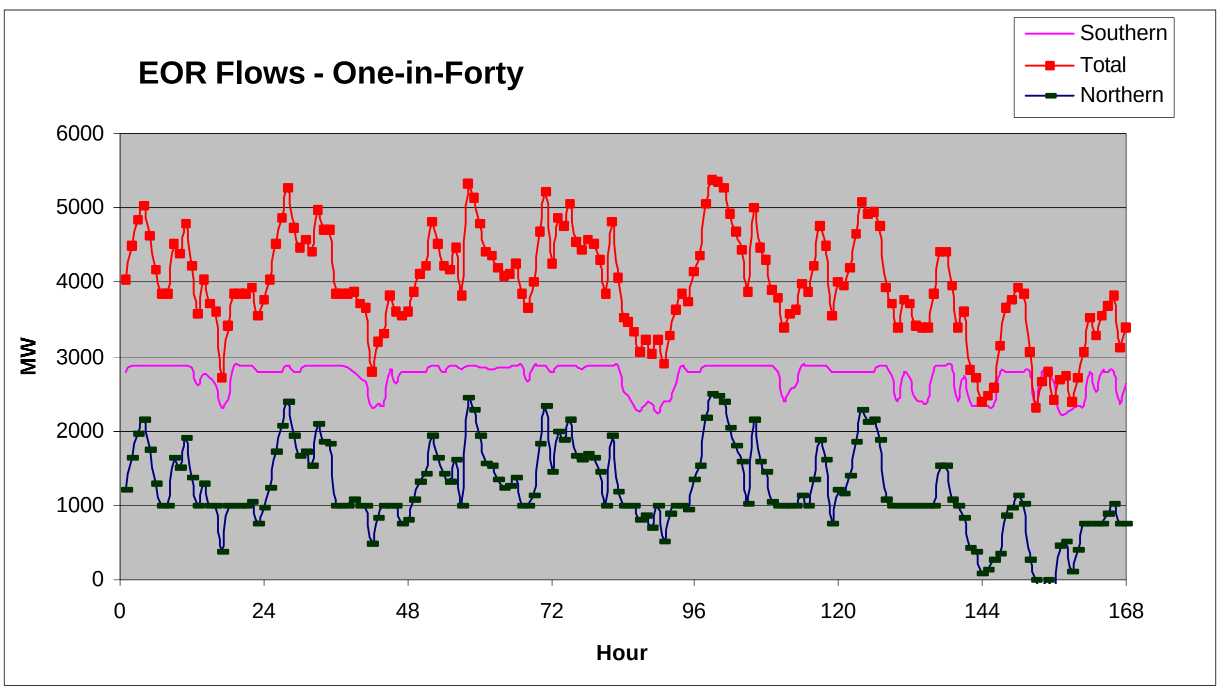
Source: Energy Commission staff.

Figure II-15
East of River Flows
Beginning Monday 12 AM Ending Sunday 11 PM



Source: Energy Commission staff.

Figure II-16
East of River Flows
Beginning Monday 12 AM Ending Sunday 11 PM



Source: Energy Commission staff.

Future Load Growth

Table II-15 below shows the expected load growth in the California ISO control area. By 2002, the expected peak demand in the California ISO control area equals the demand in our 1-in-5 year temperature scenario. By 2004, the expected demand is at the 1-in-40 year level. The consequences of a 1-in-5 or l-in-40 temperature occurrence in future years, without new resource additions, would be worse, in terms of operating reserves, than the results reported here for 1999. How much worse will depend on prevailing hydro conditions and unit availability. As each year goes by without an increase in new generation capacity in California, the probability of Stage II alerts during the summer peak demand period will increase.

Load growth in the Southwest, especially in the Southern Nevada region and Mexico, is expected to be significantly greater than load growth in California. Without new generation resource additions in the Southwest, less generation will be available from this region for export to California in the coming years. The State will, therefore, become increasingly more dependent upon imports from the Northwest to meet summer peak loads. The availability of surplus hydro energy from the Northwest, therefore, becomes critical to California being able to meet summer peak demand in the summer until new merchant plants come on line in California.

The deregulation of generation markets in the rest of the WSCC combined with low reserve margins, however, will result in increased competition for available generation. This competition means that the historical levels of imports into California from both the Southwest and Northwest cannot be relied upon to be available in the future.

Table II-15
Forecasted Coincident Peak Demand
For the CA Independent System Operator Control Area
(MW)

	1999	2000	2001	2002	2003	2004
San Francisco	878	889	901	908	923	930
Cal North	20,181	20,506	20,821	21,120	21,536	21,883
Cal South	21,191	21,253	21,654	22,143	22,664	23,186
San Diego	3,334	3,412	3,476	3,546	3,637	3,735
Total ISO	**45,584**	**46,060**	**46,852**	**47,717**	**48,760**	**49,734**

Source: Energy Commission staff.

Summary of Findings

Our modeling of the WSCC system revealed that sufficient generation and transmission capacity exist in California and the rest of the WSCC to meet peak demands associated with expected summer temperatures in 1999 as well as temperatures corresponding to a 1-in-5 year and 1-in-40 year probability. In all three cases, there was no unserved energy. However, the reliability of the system, as measured in terms of the amount of reserve capacity left over after meeting peak demand, is questionable.

In the 1-in-5 scenario, reserve margins in the California ISO control area fall below 7 percent in 5 hours during the peak demand week, but never fall below 5 percent. In the 1-in-40 scenario, reserves fall below 7 percent in 11 hours, and it is necessary in 8 of those hours to curtail interruptible load. Sufficient interruptible load is available, however, to restore a 5 percent operating reserve margin.

The reliability of the California electricity system during periods of extremely hot weather will depend in large part on outage conditions that prevail during peak demand hours and hydro availability. Reserve margins on peak are thin enough in California and the Southwest so that a dry hydro year or outages of any large unit or transmission line in California or the rest of the WSCC could seriously threaten system reliability.

In the three demand scenarios, the model shows 2,752 MW of generation in the California ISO control area being unavailable at the time of the California peak demand. This number is significantly higher than the 1,500 MW assumed by the California ISO in its ***1999 Summer Operations Plan.*** The outages generated by the model may be viewed as conservative, given that the nuclear units in the WSCC were not allowed to be forced out by the model.

In the Northwest region of the WSCC, there is a large margin of excess capacity above the region's firm demand. This excess capacity, however, reflects the significant amount of hydroelectric capacity in the Northwest, which is energy-limited. In a very wet year, we would expect that the lines from the Northwest into California would be loaded at or near their carrying capacity. Our modeling, which assumes average hydro year conditions, showed flows on the Pacific DC Intertie and the three AC lines that comprise the California-Oregon Intertie well below their maximum summer carrying capacity. For the summer of 1999, hydro availability from the Northwest is expected to be well above the average amount assumed in our analysis.

There is sufficient transmission capacity from the Northwest and Southwest to meet the firm import requirements of the California ISO. However, because capacity reserves in the Desert Southwest are lower than California's, the flows of electricity over transmission lines from the Southwest, especially those lines that comprise the northern portion of the West-of-River system, are well below the available transfer capability.

Continued load growth in California in future years means higher peak demands. As each year goes by without an increase in new generation capacity in California, the probability of Stage II alerts during the summer peak demand period will increase.

In the absence of significant amounts of new generation capacity additions in the Southwest, less generation will be available from this region for export to California in the coming years; therefore, California will become increasingly more dependent upon imports from the Northwest to meet summer peak loads.

The deregulation of the generation market in the rest of the regions of the WSCC, combined with low reserve margins, will result in increased competition for available generation. Therefore, historical levels of imports into California from the Southwest and Northwest cannot be relied upon to be available in the future.

Appendix II

Sources of Generation Capacities and Operating Characteristics

Qualifying Facilities Status Reports to the CPUC

1996 PG&E, SCE ECAC filings with the CPUC

PG&E and SDG&E ***ER 96*** Supply Forms – April 11, 1996 filed with the California Energy Commission

NERC's Electricity Supply & Demand Database – 1998

NERC’s Generating Availability Data System –1999

Energy Commission’s Energy Technology Development Division’s forecast of new renewable energy technologies, February 1999

WSCCs’ *Summary of Estimated Loads and Resources*, April 1998

WSCCs’ *Coordinated Bulk Power Supply Program 1995-2005*

Electric Power Research Institutes’ *Technology Assessment Guide*

PG&E, SCE, SDG&E Must-Run Agreement with the California ISO, Filings with the FERC, October 1997.

For data not available from the above sources estimates were made by the Multisym™ vendor, Henwood Energy Services Inc., using data filed with the FERC, the EIA.

Section III: Supply Adequacy Trends and Outlook

This section of the report looks at the trend in reserve levels for the whole WSCC and relevant sub-regions over the last 10 years. It discusses significant factors in determining reserve levels and the potential for new resource additions in the next four years. Finally, it takes a broader look at the supply and demand picture for the entire WSCC and identifies those factors that will strongly influence electricity supply adequacy in the future.

Background

In Section II, the staff evaluated the adequacy of generation capacity in California and the rest of the WSCC under average summer temperature conditions and two hot weather scenarios. Our evaluation revealed that under average temperature conditions, operating reserves in California are adequate to reliably meet load. These reserve levels declined in the hot weather scenarios and in the extreme temperature scenario interruptible load must be curtailed.

The staff's findings are consistent with the North American Electric Reliability Council's ***1999 Summer Assessment***[28] which concluded the following:

> [t]he Arizona-New Mexico-Southern Nevada and the California-Mexico areas of WSCC may not have adequate resources to accommodate a widespread severe heat wave or a significantly higher-than-normal forced outage rate for generation. Those areas are experiencing a continuing trend of peak demand growth exceeding the addition of new generation facilities."

A consulting firm, ICF Kaiser, has also issued warnings about tight western electricity supplies, especially during super hot weather conditions.[29] They speculate that price spikes would be more likely to occur in the summer of 2000 because hydro availability for the summer of 1999 is greater than normal. They also noted that demand growth in the WSCC has outpaced supply additions and that surplus hydro capacity in the Northwest masks this shortage.

WSCC Reserve Capacity Trends

Each year the WSCC, using data provided by members, provides a resource assessment for its four sub-regions. This annual assessment contains projections of capacity available to meet peak demand. The excess of forecasted available capacity over demand, or reserve margin, is the capacity available to cover unexpected outages, demand forecast errors, weather extremes, and delays in new projects coming on line.

Table III-1 compares the forecasted peak demand reserve margins to the actual level throughout the WSCC and for the California/Southern Nevada and Desert Southwest reliability sub-regions

[28] ***1999 Summer Assessment, Reliability of Bulk Electricity Supply in North America,*** North American Electric Reliability Council, June 1999, pg. 3.
[29] Power Markets Week, June 7, 1999

for the last ten years.[30] Both forecasted and actual reserves have been moving steadily downward and, since 1995, consistently downward. In 1997, California-Nevada and the Desert Southwest actual peak resources had respectively, dipped into, and below, the 7 percent range, which is the minimum operating reserve level required by the WSCC of its members.

Table III-1
Forecasted and Actual Reserve Margin
Percent of Firm* Non Coincident Peak Demand

Year	WSCC		California/Southern Nevada**		Desert Southwest**	
	Forecasted	Actual	Forecasted	Actual	Forecasted	Actual
1988	40.3	26.1	33.3	12.2	35.9	23.3
1989	35.6	27.3	29.4	21.0	32.8	18.3
1990	39.5	23.7	37.5	14.2	40.4	8.4
1991	33.1	15.3	34.4	16.0	35.1	29.3
1992	31.8	21.9	29.6	13.0	32.7	20.5
1993	29.3	18.8	28.5	17.8	32.4	22.8
1994	28.8	19.1	25.9	11.6	26.2	15.8
1995	24.5	22.8	20.4	14.3	24.3	11.7
1996	26.0	18.4	29.4	10.1	19.3	9.9
1997	28.6	16.9	25.8	7.8	19.5	6.2
1998	25.5	na	25.4	na	16.6	na
Average 1988-1997	**31.8**	**21.0**	**29.4**	**13.8**	**29.9**	**16.6**

* Does not include demands of interruptible load customers.

** In 1998, the WSCC changed the boundaries of the reporting regions. The forecasted values for 1997 reflect the old boundaries. The actual value reported for 1997, and the forecasted values for 1998, are for the redefined regions. Southern Nevada is included in the Desert Southwest (Arizona-New Mexico) region. The new California region includes Mexico.
Source: *10-Year Coordinated Plan Summary*, Western Systems Coordinating Council, Issues May 1987 through May 1998**.**

Role of Interruptible Loads in System Reliability

The forecasted and actual reserve levels in **Table III-1** represent the margin of available capacity over firm demand. Firm demand does not include the demand of interruptible customers who receive a rate discount in exchange for being willing to curtail consumption of electricity in an emergency. However, if asked to drop load, an interruptible customer could choose to stay on line and accept a financial penalty[31].

When reserve margins were very high, interruptible load customers had a very low probability of being curtailed. While utilities did their firm reserve planning as if the interruptible load did not exist, resources were usually available to serve interruptible loads. That situation is changing in the new competitive generation market, for two principal reasons. One, lower reserve margins mean that utility systems need to look to their interruptible customers as a real load shedding option. And, two, there is no market motivation to protect interruptible customers from being

[30] Compiled from the WSCC's annual ***10-Year Coordinated Plan Summary*** Issues May 1987 through May 1998.
[31] There are two types of interruptible load customers: industrial load customer who must be willing to curtail load if called upon to by the utility distribution company (UDC), and equipment such as air conditioners and agricultural water pumps that the UDC controls directly and can cycle on and off when conditions warrant.

interrupted. These customers receive a rate discount for accepting the risk of being curtailed. The market signal they send is not one that places a value on reliability.

Table III-2 shows what the forecasted and actual peak demand reserve margins would have been over the last ten years, for the same areas in **Table III-1**, after meeting interruptible (nonfirm) loads. **Table III-2** clearly illustrates that as reserve margins shrink, interruptible load customers that choose not be curtailed under tight supply conditions will adversely impact system reliability. Had the California ISO been in operation in 1997, it would have had to issue a Stage II alert. The ISO would have requested that the utility distribution companies (UDCs) curtail their interruptible load customers because they would have been unable to maintain a minimum operating reserve of 5 percent.[32]

Table III-2
Forecasted vs. Actual Reserve Capability
After Serving Interruptible Loads

Year	WSCC		California/Southern Nevada*		Arizona-New Mexico*	
	Forecasted	Actual	Forecasted	Actual	Forecasted	Actual
1988	40.3%	24.3%	33.3%	12.2%	35.9%	19.1%
1989	35.6%	23.5%	29.4%	17.1%	32.8%	13.6%
1990	34.6%	21.8%	33.3%	10.4%	32.7%	5.9%
1991	28.4%	13.4%	30.3%	11.2%	27.5%	25.9%
1992	27.1%	17.8%	24.8%	9.1%	28.5%	15.7%
1993	24.4%	14.5%	23.4%	13.2%	28.9%	17.4%
1994	24.3%	16.0%	20.7%	8.8%	22.0%	13.2%
1995	19.6%	18.4%	14.3%	10.3%	20.0%	9.3%
1996	21.0%	15.7%	22.4%	6.0%	14.7%	7.7%
1997	23.7%	14.0%	19.1%	3.7%	15.1%	3.7%
1998	21.5%		18.7%		12.8%	
Average 1988-1997	**27.9%**	**17.9%**	**25.1%**	**10.2%**	**25.8%**	**13.1%**

* In 1998, the WSCC changed the boundaries of the reporting regions. The forecasted values for 1997 reflect the old boundaries. The actual value reported for 1997, and the forecasted values of 1998, are for the redefined regions. Southern Nevada is included in the Arizona-New Mexico region. The new California region includes Mexico.
Source**:** ***10-Year*** *Coordinated Plan Summary***,** Western Systems Coordinating Council, Issues May 1987 through May 1998

It is widely acknowledged that greater demand elasticity is needed in this new competitive electricity market, not only for improving system reliability during peak demand hours, but as a means to limit volatility in market prices and improve overall market efficiency. The UDCs are designing participating load agreements so that large or aggregated customers can choose to shed load when the price would otherwise be higher than they are willing to pay. The UDC will then be able to bid the demand of participants into the PX market like any other resources.

[32] The ISO does not count interruptible load as part of its operating reserve because: 1) it is not available in ten minutes, 2) it involves a voluntary action on the part of the customer, and 3) it is not directly under their control because it entails a contract between the UDC and end-use customer under a CPUC tariff.

Difference between Forecasted and Actual Reserves

As **Table III-1** shows, the forecasted amount of reserve capacity has been consistently much higher than actual over the last ten years. The 10-year average forecasted reserve margin for California/Southern Nevada was 29.4 percent compared to the 10-year average actual reserve margin of 13.8 percent. Factors that can contribute to actual peak demand reserves being less than expected include demand forecast errors, unplanned outages, as well as delays in new projects coming on line.

Table III-3, which compares the forecasted peak demand to the actual peak, shows that forecast error accounts for a relatively small portion of the overestimate of available reserve capacity. For the whole WSCC, forecasts have generally been within two percent of actual peak. The sub-regional forecasts have not been as close, but this does not explain the wide discrepancy between actual and forecasted reserve capacity in the WSCC's annual assessment.

The factor contributing most to the difference between forecasted and actual reserves has been the convention of not including an estimate of the amount of capacity that would be unavailable due to unexpected forced outages and unplanned maintenance. The WSCC forecasts of unavailable generation appear to take into account only generation that is known to be inoperable due to extended outages (i.e., generation in cold standby), and planned maintenance. **Table III-4** shows that for the last 10 years the amount of generation that was unavailable due to extended outages and planned maintenance was far smaller than the amount of generation that was unavailable for all reasons.

In the California sub-region of the WSCC, the ten-year (1988-1997) average for the amount of generation capacity that was unavailable at the time of the region’s coincident peak demand because of maintenance or forced outages was 5,821 MW. The staff’s scenario modeling of supply adequacy under the three temperature related demand scenarios was conservative compared to this historical average in that it showed only 3,373 MW of capacity in the California-Mexico region being unavailable at the time of the peak demand.

Table III-3
Forecasted vs. Actual Peak Demand*

	WSCC			California/Southern Nevada**			Arizona-New Mexico**		
Year	**Forecasted (MW)**	**Actual (MW)**	**Difference**	**Forecasted (MW)**	**Actual (MW)**	**Difference**	**Forecasted (MW)**	**Actual (MW)**	**Difference**
1988	95,347	97,335	2.1%	43,417	46,812	7.8%	10,812	11,205	3.6%
1989	99,320	102,496	3.2%	44,998	45,252	0.6%	11,210	12,176	8.6%
1990	104,349	109,950	5.4%	46,134	50,236	8.9%	12,303	12,553	2.0%
1991	107,403	107,898	0.5%	47,365	46,924	-0.9%	12,960	11,892	-8.2%
1992	110,105	112,311	2.0%	49,502	50,929	2.9%	12,651	12,956	2.4%
1993	111,350	110,970	-0.3%	50,186	49,664	-1.0%	12,820	13,057	1.8%
1994	113,596	115,826	2.0%	51,353	52,668	2.6%	13,303	13,985	5.1%
1995	117,420	117,386	0.0%	54,113	52,510	-3.0%	13,839	14,566	5.3%
1996	118,404	123,375	4.2%	52,501	54,760	4.3%	14,678	15,087	2.8%
1997**	120,900	124,935	3.3%	48,913	53,217	8.8%	18,875	19,026	0.8%
1998	123,950			49,833			19,662		

* Includes both firm and non-firm loads.

**Starting in 1997, for both the Forecasted and Actual, Southern Nevada is included in the Arizona-New Mexico region, and the California is for California and Mexico.

Source: *10-Year Coordinated Plan Summary*, Western Systems Coordinating Council, Issues May 1988 through May 1998

Table III-4
Forecasted vs. Actual Unavailable Generation (MW)*

	WSCC			California/Southern Nevada**			Arizona-New Mexico**		
Year	**Forecasted**	**Actual**	**Difference**	**Forecasted**	**Actual**	**Difference**	**Forecasted**	**Actual**	**Difference**
1988	8,313	19,767	(11,454)	1,198	7,444	(6,246)	270	1,090	(820)
1989	9,639	22,645	(13,006)	2,150	6,422	(4,272)	236	1,824	(1,588)
1990	5,759	16,342	(10,583)	303	6,150	(5,847)	0	2,862	(2,862)
1991	9,465	24,851	(15,386)	606	7,460	(6,854)	214	677	(463)
1992	7,489	16,223	(8,734)	335	5,162	(4,827)	0	921	(921)
1993	7,453	16,301	(8,848)	1,162	4,519	(3,357)	1	1,379	(1,378)
1994	6,954	12,457	(5,503)	839	4,579	(3,740)	255	967	(712)
1995	7,638	14,035	(6,397)	1,027	5,215	(4,188)	16	1,015	(999)
1996	7,665	12,243	(4,578)	418	6,237	(5,819)	24	586	(562)
1997**	6,446	12,795	(6,349)	280	5,019	(4,739)	17	608	(591)
1998	5,741			0			17		

* Actual Unavailable Generation includes Maintenance, Forced Outages, and Inoperable Capacity

** In 1998, the WSCC changed the boundaries of the reporting regions. The forecasted values for 1997 reflect the old boundaries. The actual value reported for 1997, and the forecasted values for 1998, are for the redefined regions. Southern Nevada is included in the Arizona-New Mexico region. The new California region includes Mexico.

Source**:** *10-Year Coordinated Plan Summary***,** Western Systems Coordinating Council, Issues May 1988 through May 1998

Aging Power Plants and System Reliability

As they age, power plants require more maintenance and their reliability declines. Oil and natural gas-fired power plants typically have design lives of 30 to 40 years. In California, almost half of the installed generation capacity in the state is comprised of oil and natural gas-fired combustion turbines, steam turbine, combined cycle, and cogeneration units. **Table III-5** shows that 61 percent of that capacity is thirty years or older.

Table III-5
Age of Oil and Gas-Fired Plants
In California

Age	Summer Capacity (MW)	Percent of Total
40 years or older	5,276	20%
30 - 39 years	10,542	41%
20 - 29 years	5,527	21%
Less than 20	4,509	17%
Total	25,854	100%

*Oil/Gas-fired Steam, Combustion Turbine, Combined-Cycle, Cogeneration Units listed as Operational in the NERC 1998 Electricity Demand & Supply Database.

Source: Energy Commission staff.

Most of this older capacity is made up of units that were, once owned by the three California investor-owned utilities that are now divested. Because of the strategic location of these plants on the transmission grid, many of them have one-year RMR contracts with the California ISO. Older units under an annual RMR contract are likely to be adequately maintained to ensure their availability during that year's peak load season. The new owners of these facilities are expected to provide maintenance on these units that is consistent with a standard of what is considered "Good Industry Practice." Improved maintenance on California RMR units to increase their availability will contribute to greater reliability during the summer peak demand season, but it will not be enough to reverse the trend of declining reserve margins.

Even with improved maintenance, many of these older California units will have to be out of service for an extensive period to install required emission control devices for oxides of nitrogen (NO_x). The installation of NO_x emission controls devices will also be required for fossil units throughout the WSCC. The timing of any NO_x retrofit or plant refurbishment activity could result in one, or more, large thermal units being unavailable during the summer peak demand season; therefore, keeping track of this activity will have important consequences for system reliability.

Outlook for New Generation

The outlook for new generation additions in the near term, as reported by the WSCC, will not keep pace with expected demand growth. **Table III-6** shows that expected new generation additions in the WSCC over the next four years will consistently lag demand growth.[33]

Table III-6
Incremental Growth in Demand
Compared to Net Generation Additions (MW)

Year	WSCC		CA-MX		AZ-NW-SN	
	Incremental Summer Peak Demand Growth	Net Generation Additions	Incremental Summer Peak Demand Growth	Net Generation Additions	Incremental Summer Peak Demand Growth	Net Generation Additions
1998		252				2
1999	2,646	1,049	763	150	657	81
2000	2,322	1,326	405	717	723	207
2001	2,453	1,252	678	240	678	91
2002	2,257	2,043	940	660	641	157
2003	2,797	372	1,202	496	581	242

Source**: *10-Year Coordinated Plan Summary 1998-2007,*** Western Systems Coordinating Council

The WSCC forecast for the California-Mexico region includes three merchant power plants:

- the Sutter Combined Cycle unit (510 MW), which has an on-line date of December 2000, and, therefore, would not be available for the summer peak season of 2000;
- the San Francisco AES cogeneration project (240 MW) in January 2001; and
- the Otay Mesa project (660 MW) in San Diego with an on-line date of May 2002.

Of these three projects, only Sutter has received siting approval from the Energy Commission; the other projects have not submitted an application for siting. Several other projects, however, are in the Commission's siting cue. They include the following:

Delta Energy Center (98-AFC-3)
Duke Energy Moss Landing Power Plant Project (99-AFC-4)
Elk Hills Power Project (99-AFC-1)
High Desert Power Plant Project (97-AFC-1)
La Paloma Generating Project (98-AFC-2)
Metcalf Energy Center Power Project (99-AFC-3)
Pittsburg District Energy Facility Project (98-AFC-1)
Sunrise Cogeneration and Power Project (98-AFC-4)
Three Mountain Power Plant Project (99-AFC-2)

[33] The WSCC relies on its members to submit data on planned resource additions. Some members may regard such information as competitive and/or sensitive and, therefore, may not wish to advertise their intentions until required.

Based on these applications, the Commission staff has put together a plausible scenario of future resources additions, which is shown in **Table III-7**

Table III-7
CEC Staff Forecast of
Net Incremental Additions in the WSCC

Area	2000	2001	2002	2003
PG&E N. Path 15	-	1,000	2,922	546
San Francisco.	-	-	553	-
PG&E S. Path 15	-	-	2,537	400
SCE	(158)	680	2,931	1,500
SDG&E	-	-	1,052	-
Cal. ISO Control	**(158)**	**1,680**	**9,995**	**2,446**
LADWP	-	-	10	-
IID	-	-	559	-
Total California	**(158)**	**1,680**	**10,564**	**2,446**
CFE	350	150	150	450
Total CA. MX	**192**	**1,830**	**10,714**	**2,896**
AZ-NM-SN	751	586	-	86
Pacific NW	126	239	1,079	-
Rocky Mtn.	238	-	-	-
Total WSCC	**1,307**	**2,655**	**11,793**	**2,982**

Source: Energy Commission staff.

While the Energy Commission staff supply picture for the California ISO control area is more robust than that of the WSCC, it still shows that until 2002 new resource additions in all parts of the WSCC region will not keep up with demand growth. There also is a high degree of uncertainty with respect to the on-line date of many of these new merchant plants in California.

The timing of construction for these new units in California will depend not only on how quickly they proceed through the Energy Commission permitting process but also on the market signals coming out of the California Power Exchange (PX) and the ISO. The Energy Commission staff's forecast of PX market clearing prices assumed that new power plants will enter the market when their owners are assured of being able to recover the plant's annual revenue requirements. The market signals coming out of the PX and ISO, however, have been mixed because of market design problems. The presence of RMR contracts has the same affect. The terms of these contracts directly influence how and when generators with these contracts will bid into the PX energy market.[34] The ISO's Market Surveillance Unit noted these problems in its ***Annual Report on Market Issues and Performance,*** June 1999, and is continuing to work towards solving them.

[34] Price caps on any of the markets for energy or ancillary services also affect when and what market generators bid into and, therefore, can contribute to market uncertainty and the timing of new resource additions as well.

Looking Beyond California

Operating reserves in California cannot be looked at in isolation from the rest of the WSCC. Operating reserves in other regions of the WSCC are just as thin as in the California-Mexico Region. While the Northwest appears to have excess capacity, most of that excess capacity is from hydroelectric facilities that may or may not have the energy in the form of water to back it up. The Rocky Mountain Region's ability to help the Southwest during the summer peak season is also doubtful. On July 17, 1998, Public Service of Colorado (PSCo) instituted rolling blackouts. They missed their peak demand forecast by 400 MW when consumption peaked at 4,800 MW. PSCo subsequently announced that they would need 675 MW of additional power in 2000, rather that the 169 MW that they had originally forecasted prior to the summer heat wave. New Centuries Energy, the parent company of PSCo, announced that they would pursue plans for building a 300-mile 345 kV transmission line from Amarillo, Texas to Denver. The line will come on-line in 2001 and have an initial capacity of 210 MW.

As noted in Section II, there will be a highly competitive market for new generation that is added in the WSCC, especially from areas like Mexico and Southern Nevada that are experiencing growth rates twice that of the rest of the WSCC. The officials at the Commision Federal de Electricidad (CFE), Mexico's state power company, have been quoted as saying that the country needs to add an average of just over 1,000 MW per year over the next decade to keep up with demand. The demand for electricity in some areas of Mexico is growing at an annual rate of between 7 and 8 percent.

While some of this increase in demand will be met with new generation located in Mexico, there are at least 3 proposals on the table for new transmission lines from the WSCC to Mexico. The Department of Energy has been holding a series of environment impact statement scoping meetings on proposed transmission lines from the Palo Verde Generating Station in Arizona to Mexico. NRG Energy, a subsidiary of Northern States Power Company, is proposing a new 500 kV AC transmission line from the Palo Verde switchyard to the Cetys switchyard in Mexico near Mexicali. ALSTOM and Public Service of New Mexico have proposed to jointly develop a line originating at the Palo Verde Station to the border near Calexico. The line would have an 800 to 1000 MW transfer capability. The Imperial Irrigation District is also looking to increase the number of ties to Mexico by building a short 230 kV from its Bravo substation to Calexico.

The Nevada Power Company, which supplies Las Vegas's electricity, is struggling to keep up with demand that was up nearly 6 percent from last year. They are installing the world's largest phase-shifting transformer at a site near Las Vegas. This installation is part of the Crystal Transmission Project that will increase NPC's import capability by 850 MW. Another project in the works to increase Las Vegas's import capability is Composite Power Corporations proposed an 850-mile high voltage DC transmission line from the Dalles, Oregon. The line would be extended over an existing right-of-way. Composite hopes to use the line to transport generation from a variety of sources including a pumped hydro-electric storage facility in Southern Oregon, several hundred MW of solar energy in Death Valley, Nevada, and a 250 MW wind farm in the State of Washington. These new transmission lines and phase shifters do not contribute new capacity, but they do signal a redirection of the historical flows of electricity over the bulk transmission network in the WSCC.

From our evaluation of the status of the supply system in California and the rest of the WSCC, capacity margins will continue to dwindle over the next three years, as will the reliability of the system under unusually severe weather conditions. The risks and costs of supply disruptions are the sole burden of consumers in this new competitive market. The fact that other states in the WSCC are in various stages of deregulation and opening up their generation supply market to competition means that there will continue to be a high degree of uncertainty as to the financial viability of new market entrants. In their report *Reliability Assessment 1998-2007, The Reliability of the Bulk Electric Systems in North America*[35]the North American Electric Reliability Council noted that future generation investment will occur only in response to there being proper marketplace signals defining financial incentive, investment risk, and potential returns. The NERC report concludes that to ensure continuing resource adequacy, the risk of failing to serve the customer must be recognized and incorporated into the price structure.

Incorporating the risk of failing to serve customers into prices will not result in reliable service if customers have no way of sending price signals which indicate what they are willing to pay for reliability. The long-range technical solution to this problem would be for all consumers to have time-of-use meters and direct end-use load control devices programmed to respond to price signals. Absent a technology solution, or a charge that allows customers to indicate the level of reliability that they are willing to pay for, the market may periodically be unable to ensure adequate reliability. This raises the question of whether the customer must be served at all times. If the answer is yes, then who bears this responsibility for ensuring a minimum level of reliability for all customer loads? Regulators? The California ISO? And how is this responsibility to be implemented?

Part of that responsibility will entail periodic assessments of supply adequacy for the entire WSCC region to determine the amount of generation capacity available to meet load and provide a check on the performance of the market and its success at attracting new capacity. This means that there must be reasonably accurate demand forecasts on a regional level that take into account the import capability among regions, as well as extreme temperature conditions, variations in assumed hydro conditions, and unit availability. These last three factors have a significant impact on market price volatility; therefore an assessment of the effect of these factors on electricity demand and supply provides important information to the developers of new power plants who are trying to estimate their profitability.

Summary of Findings

Peak demand reserve capacity has been declining in the California and Desert Southwest regions of the WSCC for the last 10 years. The North American Electric Reliability Council has noted that capacity shortfalls in these regions would be likely in the event of extreme temperature conditions during the summer peak demand season or significantly higher-than-normal forced outages for generation.

Without significant amounts of new generation capacity being added in California and the rest of the WSCC, the likelihood that the California ISO will have to rely on curtailing interruptible load customers during the summer peak demand season will increase. Interruptible load customers that choose not to be curtailed when called upon will adversely impact system reliability. Greater demand elasticity is needed in the market not only improve system reliability during

[35] *Reliability Assessment 1998-2007, The Reliability of the Bulk Electric System in North America,* September 1998, North American Electric Reliability Council.

peak demand hours, but also limit volatility in market prices and improve overall market efficiency.

The WSCCs' annual forecast of capacity reserve margins at the time of peak demand for the four sub-regions has consistently been higher than the actual margin. The factor contributing most to the forecasts overstating the amount of peak reserve capacity has been the fact that the forecast does not include an estimate of the amount of capacity that is unavailable at the time of the peak because of unplanned maintenance and forced outages.

In the California sub-region of the WSCC, the ten-year (1988-1997) average for the amount of generation capacity that was unavailable at the time of the region's coincident peak demand because of maintenance or forced outages for was 5,821 MW.

Age is significant factor affecting a power plant's reliability. In California, 15,818 MWs of oil and natural gas-fired capacity in the State is thirty years or older; therefore forced outages will play an important role in the future reliability of the California electricity system during the summer peak demand season.

Forced outages are not the only factor affecting the availability of generation in California. Over the next three years fossil fuel-fired units in California, and the rest of the WSCC, will have to be out of service for some period of time to install required NO_x control devices.

If the new merchant power plants proposed for construction in California are built, they will reverse the trend in declining reserve margins. Unfortunately, most of the merchant plants would not come on-line until 2002 and 2003. In addition, there is, however, a high degree of uncertainty surrounding the on-line dates for these plants. The timing of these new additions depends not only on how quickly they proceed through the Energy Commission's siting process, but also on the market signals coming out of the California PX and ISO.

There will be a highly competitive market for new generation added in the WSCC, especially among those regions where peak reserve capacity is low and demand growth is high. New transmission projects, proposed, and under construction, in the WSCC signal a redirection of historical flows of electricity over the western bulk transmission network.

The NERC has stated that future generation investment will only occur in response to proper marketplace signals, and that to ensure continuing resource adequacy, the risk of failing to serve the customer must be recognized and incorporated into the price structure. However, incorporating the risk of failing to serve customers into prices will not result in reliable service if customers have no way of sending price signals which indicate what they are willing to pay for reliability. This brings into question the whether customers must always be served, and if regulators or the ISO have a responsibility of ensuring a minimum level or reliability for all customer loads.

Whoever has that responsibility will have to make periodic assessments of supply adequacy for the entire WSCC region to determine the amount of generation capacity available to meet load and provide a check on the performance of the market and its success at attracting new capacity.